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INVESTIGATING THE EFFECTS OF JP-8 USE IN HEATING PLANT BOILERS

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13. ABSTRACT *(Maximum 200 words)*

THE OBJECT OF THIS PROJECT WAS TO INVESTIGATE THE OPERATIONAL AND ENVIRONMENTAL EFFECTS ASSOCIATED WITH BURNING AVIATION FUEL JP-8 IN TRADITIONAL HEATING PLANT BOILERS. JP-8 WAS COMPARED TO #2 FUEL OIL AND DIESEL FUEL IN SMALL-SCALE TESTING AT TYNDALL AFB FL AND DIESEL FUEL IN FULL-SCALE TESTING AT McCLELLAN AFB CA. SYSTEM PERFORMANCE WAS EVALUATED WITH RESPECT TO THE BOILERS' THERMAL EFFICIENCIES, FUEL PUMP AND BURNER PUMP PERFORMANCE, AND ENVIRONMENTALLY SIGNIFICANT COMBUSTION PRODUCTS. THE OPERATIONAL PERFORMANCE OF JP-8, IN COMPARISON WITH DF-2 AND FUEL OIL, WAS SATISFACTORY, WITH FUEL TO STEAM CONVERSION RANGING FROM 7 PERCENT LESS WITH JP-8 TO PERFORMANCE THAT EXCEEDED THAT OF #2 FUEL OIL AND DF-2. THE CALCULATED THEORETICAL DROP IN HEAT OUTPUT WHEN SWITCHING FROM DF-2 OR #2 FUEL OIL TO JP-8 IS APPROXIMATELY 10 PERCENT, BASED ON THE ENERGY VALUE OF THE FUELS. STACK EMISSIONS SHOWED A SIGNIFICANT DROP IN SO_x WITH JP-8, AND LOWER VALUES OF NO_x AND PARTICULATE. THERE WAS NEGLIGIBLE DIFFERENCE BETWEEN THE ORGANIC MEASUREMENTS AMONG THE FULL-SCALE TEST CONDITIONS. THE RESEARCH CONDUCTED IN SUPPORT OF THIS EFFORT WAS DESIGNED TO PROVIDE GUIDANCE TO THE BASE CIVIL ENGINEER AND THE BOILER OPERATOR TO ALLOW SAFE,

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EFFICIENT, AND ENVIRONMENTALLY CLEAN OPERATION OF EXISTING AIR FORCE BOILER SYSTEMS WITH JP-8.

EXECUTIVE SUMMARY

The concept of providing a single fuel for all Air Force operations in the Pacific Air Force (PACAF) arena has driven the requirement to investigate the operational and environmental performance of the aviation fuel JP-8 in heating plant boilers.

The research conducted in support of this effort was designed to provide general guidance to the base civil engineer and the boiler operator to allow safe, efficient, and environmentally clean operation of existing AF boiler systems with JP-8.

To enable thorough evaluation of JP-8 performance in boilers, this effort was divided into small-scale testing at Tyndall AFB, FL and full-scale testing at McClellan AFB, CA. System performance was evaluated with respect to the boilers' thermal efficiencies, fuel pump and burner performance, and environmentally significant combustion products. Additional full-scale analyses included load response, safety control aspects, and boiler operator evaluation.

Small-scale testing was conducted in a 196,000 BTU per hour, pressure atomized unit for over 250 hours. The operational and environmental performance of JP-8 was compared to #2 fuel oil and diesel fuel 2 (DF-2).

Full-scale testing, accomplished for over 160 hours, compared JP-8 to DF-2. The McClellan AFB tests were conducted in a 25,000 pound per hour water tube boiler that was capable of either steam atomization or air atomization, when operating with a secondary fuel, such as DF-2 or JP-8. Primary fuel for this boiler is natural gas.

The operational performance of JP-8, in comparison with DF-2 and #2 fuel oil, was satisfactory, with fuel to steam conversion ranging from 7 percent less with JP-8 to performance that exceeded that of #2 fuel oil and DF-2. The calculated theoretical drop in heat output when switching from DF-2 or #2 fuel oil to JP-8 is approximately 10 percent, based on the energy value of the fuels.

Tested fuel transport pumps experienced up to a 3 percent drop in output pressure when using JP-8. This drop may impact those systems that are dependent on the transport pump to provide the appropriate delivery pressure to the burner. Tested burner fuel pumps experienced no constraints from the fuel properties of JP-8. There was an increase in fuel line and auxiliary equipment leakage (which was easily stopped by tightening the junction points) after the switch to JP-8. Firebox soot buildup was significantly less with JP-8 than #2 fuel oil or DF-2. This reduction should reflect in fewer maintenance requirements with JP-8.

Stack emissions showed a significant drop in SO_x with JP-8, and

lower values of NO_x and particulate. There was negligible difference between the organic measurements among the full-scale test conditions.

The results of this study demonstrate that JP-8 can be an effective fuel for boiler combustion. The option of achieving successful boiler operation with JP-8 as the primary or secondary fuel has potential to dramatically reduce logistics requirements throughout the armed forces installations.

PREFACE

This report was prepared by the Air Force Civil Engineering Support Agency, Research, Development, and Acquisition Division, Air Base Operability and Repair (RACO) and Environmental Interactions (RAVC) Branches and Applied Research Associates (ARA). ARA efforts were performed under SETA Contract Number F08635-C-88-0067.

Significant effort on the part of 325 CES, McClellan AFB, CA made full-scale testing possible. The authors acknowledge the operational and technical assistance provided by MSgt Martin Estrada, 325CES/DEMNO.

This report summarizes work done between June 1990 and July 1991. LeAnn B. Tichenor was the AFCESA Project Officer.

This report has been reviewed by the Public Affairs Office and is releasable to the National Technical Information Service (NTIS). At NTIS, it will be available to the general public, including foreign nations.

This technical report has been reviewed and is approved for publication.

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LIST OF ABBREVIATIONS

A	Air
API	American Petroleum Institute
BL	Baseline
BTU	British Thermal Units
CFM	Cubic Feet per Minute
CO	Carbon Monoxide
COMPL	Complete
cSt	Centistokes
DF-2	Diesel Fuel 2
GAL	Gallon
GPH	Gallon per hour
Hr	Hour
L	liter
Lb	Pound mass
NATO	North Atlantic Treaty Organization
NO_x	Oxides of Nitrogen
mg	milligram
O_2	Oxygen
OPT	Optimized
PACAF	Pacific Air Command
PAH	Polynuclear Aromatic Hydrocarbons
Perf	Performance
PPH	Pounds per hour
SO_x	Oxides of Sulfur

LIST OF ABBREVIATIONS (COMPLETED)

St	Steam
STM	Steam
USAFE	United States Air Force-Europe

SECTION I

INTRODUCTION

A. OBJECTIVE

The objective of this technical report is to evaluate the operational and environmental effects associated with burning JP-8 in heating plant boilers.

B. BACKGROUND

Presently the Air Force operates with a variety of fuels to meet specific needs. These include jet fuels (that is, JP-4 and JP-8) for air operations and diesel, fuel oils, natural gas, etc., for land functions. Survivability and logistics requirements have driven the concept of providing a single land-based fuel to meet all airbase fuel needs in the Pacific Air Force (PACAF) region. Kerosene-based JP-8 will be that single fuel.

Air operations will not be significantly impacted by a conversion, as shown by successful operation with JP-8 at United States Air Force Europe (USAFE) sites*. Ground equipment, such as generators, heavy equipment, and vehicles, have been tested extensively by the Army with favorable results (1). A third use, heating plant boilers, has not been fully tested.

C. SCOPE

To enable thorough evaluation of JP-8 performance in boilers, this effort was divided into small-scale testing at Tyndall AFB, FL and full-scale testing at McClellan AFB, CA. System performance was evaluated with respect to the boilers' thermal efficiencies, fuel pump and burner performance, and environmentally significant combustion products. Additional full-scale analyses included load response, safety control aspects, and boiler operator evaluation.

The research conducted in support of this effort was designed to provide guidance to the base civil engineer and the boiler operator to allow safe, efficient, and environmentally clean operation of existing AF boiler systems with JP-8.

The option of achieving successful boiler operation with JP-8 as the primary or secondary fuel has potential to dramatically reduce logistics requirements throughout the armed forces installations. When considering fewer fuel supply actions and storage requirements, conversion is expected to result in an overall cost savings, while meeting military mission requirements and improving airbase survivability (2,3).

* Sorenson, Lt Col Houston (USAF/LFSF), Telecon, 28 Aug 91

SECTION II

FUEL-BOILER INTERFACE

Air Force operations can be divided into three geographical areas of command, PACAF, USAFE, and continental United States (CONUS). Full conversion to JP-8 in the pacific arena has started (beginning in 1991), with completion scheduled for 1996. USAFE air operations have been fully converted to JP-8: facility support with single fuel supply limited to wartime operations only. CONUS conversion of air operations to JP-8 has not been programmed, nor is the concept of single fuel supply imminent for these stateside locations*.

A. FUELS

Jet fuel JP-8 is a kerosene-type aviation turbine fuel and is interchangeable within the North Atlantic Treaty Organization (NATO) under NATO code Number F-34. The military specification allows the addition of five different additives in JP-8 (3). These include:

1. Fuel System Icing Inhibitor (FSII): conforms to Military Specification MIL-I-27686. FSII prevents the formation of ice crystals at low temperatures and improves resistance to microbiological growth; which, in turn, can reduce fuel-system corrosion. This compound is typically ethylene glycol monomethyl ether. FSII is mandatory in JP-8, but optional in the diesel fuels.

2. Corrosion Inhibitor: conforms to Military Specification MIL-I-25017. The addition of corrosion inhibitors reduces the amount of particulate contamination into the fuel in addition to inhibiting fuel system corrosion. Inhibitors also improve the lubricity of the fuel and will reduce wear in the fuel pumps. Corrosion inhibitors are mandatory in JP-8 and in diesel fuels outside of CONUS, but are not required in diesel fuels within CONUS.

3. Static Electric Dissipator: two formulations are approved. This additive increases the conductivity of the fuel to within 200 to 600 picosiemens per meter; which, in turn, minimizes the static buildup resulting from fluid flow. This safety benefit is available with JP-8, but is not mandatory for diesel fuel (DF-2) fuels.

4. Metal Deactivator: this additive is not mandatory. Its purpose is to passivate metallic materials in fuels that may

* Sorenson, Lt Col Houston (USAF/LFSF), Telecon, 28 Aug 91

degrade the thermal or storage stability of the fuel. Use of a metal deactivator is encouraged for diesel fuels outside of CONUS or long-term storage.

5. Antioxidant: twelve compounds are qualified as antioxidants for JP-8. These compounds minimize the formation of gums and peroxides. Its use is allowed in diesel fuels, but is not mandatory.

JP-8 varies from Jet A-1 (commercial aviation fuel) through the addition of a FSII, a static electric dissipator, and a corrosion inhibitor. Jet A-1 is the standard for the international commercial aviation industry, while Jet A is the standard used within the U.S. for domestic flights alone. Jet A varies from Jet A-1 in freeze point specifications only: Jet A specifies -40°F and Jet A-1 requires -52.6°F.

JP-5 is essentially the same fuel as JP-8, but varies in minimum flashpoint requirements. Flashpoint is a measure of the lowest temperature at which a flash flame can be produced (caused by the combustion of lightweight hydrocarbons) at ambient pressure. From a safety standpoint, it is necessary to maintain the flash-point above 100°F (4). The minimum flashpoint requirement for JP-5

TABLE 1. MILITARY REQUIREMENTS FOR SPECIFIC FUEL PROPERTIES*

PROPERTY	DF-2	#2 FUEL OIL	JP-8	JP-5	JP-4
** °API GRAVITY	34.5	30	45.4	41.1	55.3
VISCOSITY @ 40 °F, cSt	2.8	2.8	1.2	1.5	0.56
NET HEAT OF COMBUSTION (Btu/gal)	130,319	141,000	123,138	125,270	118,124
FLASHPOINT (°F)	125.6	100.4	100.4	140	***

* Additional properties are listed in Appendix A

** °API=(141.5/specific gravity) - 131.5

*** Less than ambient temperature, not measured is 140°F, while the minimum for JP-8 is 100°F. A recent survey of JP-8 and JP-5 fuels provided under worldwide contract showed an average flashpoint of 144°F for JP-5 and 115°F for JP-8 (5). JP-5 is the single fuel of choice for the Navy due to the higher minimum flashpoint needed to meet shipside requirements.

Heating oil #2 and diesel have many similar characteristics, and are the primary fuels used by PACAF and USAFE in their boilers. Differences between JP-8, other aviation fuels, and the diesel fuels (to include #2 fuel oil) can be seen when comparing the military specifications for fuel properties in Table 1 and Appendix A (6,7,8,9). Key differences exist between heat of combustion, viscosity, flashpoint, and American Petroleum Institute (API) gravity. It is interesting to note that the minimum flashpoint requirement for #2 fuel oil matches that of JP-8.

B. BOILERS

The Air Force boiler inventory is extensive, with capacities ranging from 0.5 million to 200 million Btu/hr. These boilers provide steam for heating buildings, along with direct support of aircraft maintenance functions, laundries, dining facilities, and hospitals. Installed fire and water tube boilers operate with a variety of burners. Fuel atomization methods include pressure, rotary cup (centrifugal), steam, and air. Primary and secondary boiler fuel supply may be natural gas, diesel, #2 through #6 fuel oils, or coal.

The PACAF boiler, burner, and fuel pump inventory is included as Appendix B. This information was compiled from the Corps of Engineers Civil Engineering Research Laboratory (CERL) Heating Plant Database, with supplemental information provided by the individual airbases through HQ PACAF.

C. PREVIOUS TESTING WITH JP-8

JP-8 boiler testing was accomplished at RAF Mildenhall UK in December 1986 (10). Test duration was limited to 1 hour at low fire and 2 hours at high fire. Comparisons between the United Kingdom equivalent of DF (35 seconds) and JP-8 reported a 15 percent reduction in heat output when operating with JP-8. Thorough review of the data concluded that only a 10 percent drop in heat output would result for a given volume of fuel. Boiler efficiencies (heat output divided by heat input) were almost identical, with JP-8 slightly higher at the high fire rate (combustion efficiency of 86.14 percent versus the diesel fuel combustion efficiency of 85.61 percent). Similarly, the low fire showed an efficiency of 86.18 percent for the JP-8 versus 86.03 percent for the diesel fuel. RAF Mildenhall is presently operating their boilers with a mixture of 60 parts (by volume) diesel to 40 parts JP-8. This combination has eliminated the waxing problems exhibited when operating at lower temperatures with the straight diesel.

Preliminary investigation of the performance of JP-8 in traditional boilers also revealed the use of JP-8 in two boilers at the Air Force (AF) installation on Ascension Island. These small (50 hp) units provide steam for an evaporative desalination unit. Rather than combusting straight JP-8, a mixture of 2 gallons of lubricating oil to 1000 gallons of JP-8 is used, based upon standard guidance concerning the use of JP-8 mechanical systems. The Ascension Island boilers have operated with the United Kingdom-supplied JP-8 with no adverse affects attributed to the JP-8/lubricating oil mixture for the last 5 years.

The United States Navy performed a series of tests using JP-5 in their shipside boilers in the 1960s, resulting in JP-5 as the primary fuel in their operations. They found that even intermittent firing of JP-5 resulted in reduced soot buildup, thus reducing maintenance requirements (11,12,13).

Discussion with various pump, boiler, and burner manufacturers revealed no published or acknowledged experience with JP-8 in their systems. A listing of those vendors contacted is available as Appendix C.

It was determined that a testing program was necessary to quantify the operational performance of straight JP-8 for a specific time period and determine the environmental emissions resulting from burning this fuel in a boiler.

SECTION III

DESCRIPTION OF TESTING FACILITIES

To enable a thorough evaluation of JP-8 performance in boilers, the testing effort was divided into a small-scale test in a boiler specifically assembled for this purpose at the Air Force Civil Engineering Support Agency at Tyndall AFB, FL and a full-scale test at McClellan AFB, CA. System performance was evaluated with respect to the boiler's thermal and combustion efficiencies, heating system thermal capacity, fuel pump performance, overall burner performance, environmentally significant combustion products, the effect of liquid JP-8 on the auxiliary equipment, and effects of JP-8 combustion products on the materials of the combustion chamber. Additional full-scale analyses included flame pattern evaluation, load response, safety control aspects, and boiler operator evaluation.

The performance of JP-8, with no added lubricating oil, was compared against diesel fuel and #2 fuel oil in the small-scale test, while the full-scale test used diesel fuel as a baseline. In both tests, JP-8 was burned at the baseline air-to-fuel ratio of the reference fuels before adjusting the settings to optimize its performance.

A. TYNDALL AFB

The laboratory setup was composed of a heating system, cooling water system, fuel delivery system, and a PC-based data acquisition system. The experimental layout is shown in Figure 1. Recorded information points are indicated by "P" for pressure, "T" for temperature, and "F" for flow. The heating system was a 196,000 BTU/hr Columbia steam water-tube boiler equipped with a Beckett pressure atomizing burner. The burner unit was comprised of a cadmium sulfide flame sensing cell, a controller to provide intermittent ignition via a 10,000-Volt electrode transformer set with a 15-second trial before fuel cutoff, atomizing nozzle of 0.8 to 1.65 gal/hr capacity, and a Suntec fuel pump. Fuel flow rate was adjusted by changing the fuel pressure at the atomizing nozzle; a pressure of 100 psig equated to a delivery of 1.4 gal/hr of #2 fuel oil. The laboratory setup was designed to operate continuously at full load with a normal operating pressure of 5 psig.

In addition to the Suntec fuel pump, a separate, closed-loop recirculation line was installed to test the performance of a relatively new two-stage gear pump made by Webster.

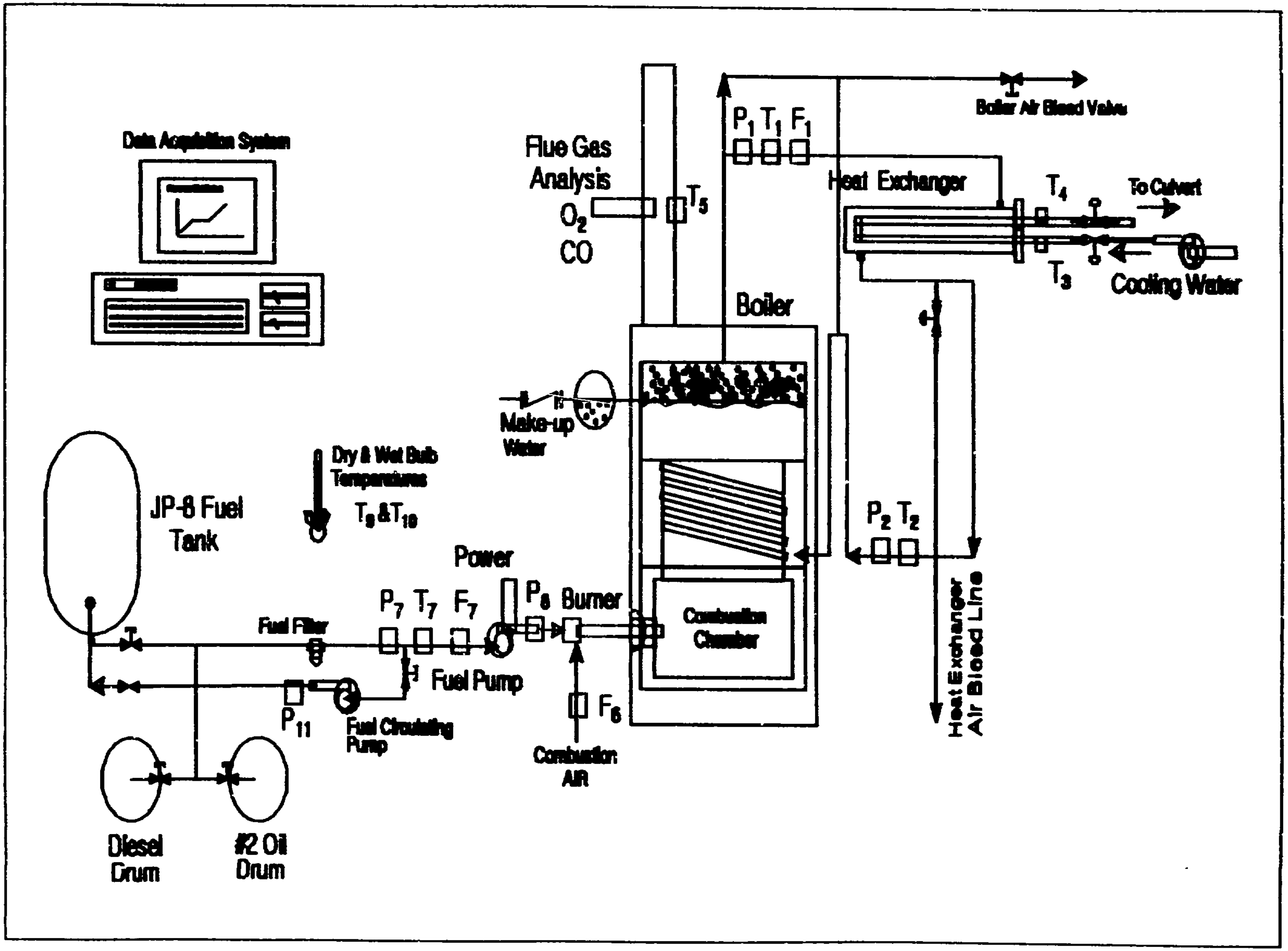


Figure 1. Small-scale Test Assembly

B. MCCLELLAN AFB

Full-scale testing was performed in a dual-fuel, 25,000 lb/hr (at 125 psig) Nebraska Boiler Company boiler fitted with a low NO_x/low excess air Coen Company, Inc. burner. The water tube boiler operates at 125 psig saturated steam pressure. Feedwater is supplied at approximately 212°F to the economizer. Manufacturer estimated performance shows a boiler efficiency of 78.9 percent when operating with natural gas (primary fuel) and 82.7 percent with #2 fuel oil (diesel used as secondary fuel). The predicted efficiency curve for firing #2 fuel oil, 125 psig operating pressure, 212°F feedwater to the economizer, 10 percent excess air and a higher heating value (HHV) of the #2 fuel oil of 19,460 Btu/Lb is shown in Figure 2. Control is accomplished via steam pressure feedback signal to the single point burner; intake air follows the fuel flow. The burner can use either steam or air as the fuel atomizing agent, and both mediums were tested.

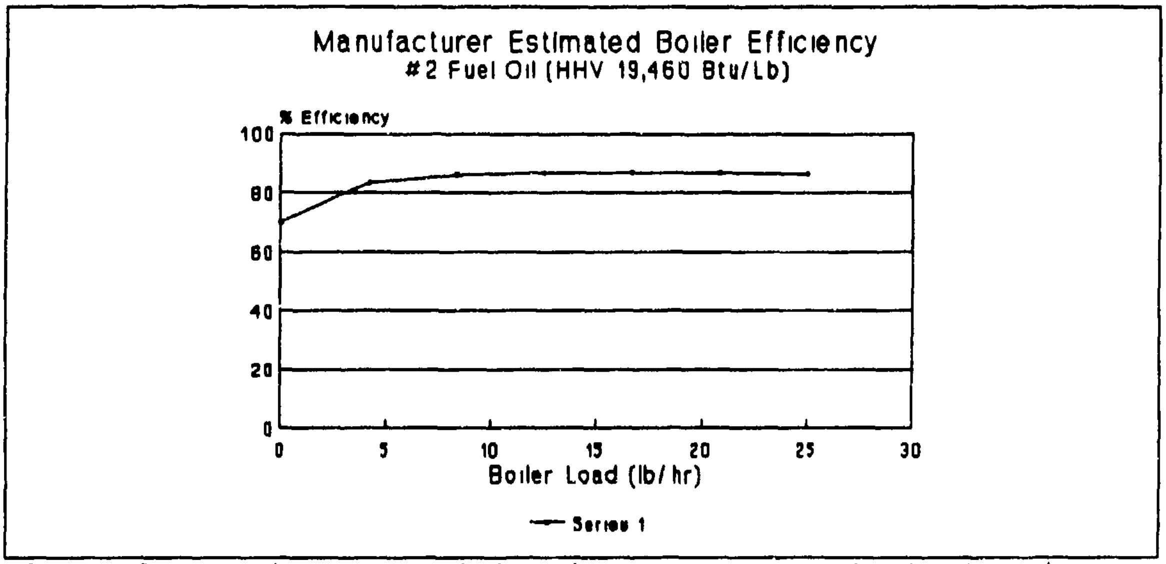


Figure 2. Estimated Efficiencies: NEBRASKA 25,0000 lb/hr Boiler, McClellan AFB, CA

JP-8 was provided through connection to a temporary 6000-gallon storage tank placed at the site. Temporary line construction was minimal in an effort to maximize testing of existing line, junctions, and valves. Fuel was provided to the burner through operation of one of two pumps: one with a rated capacity of 160 psig and the other at 90 psig. A flow diagram of the full-scale boiler is shown in Figure 3.

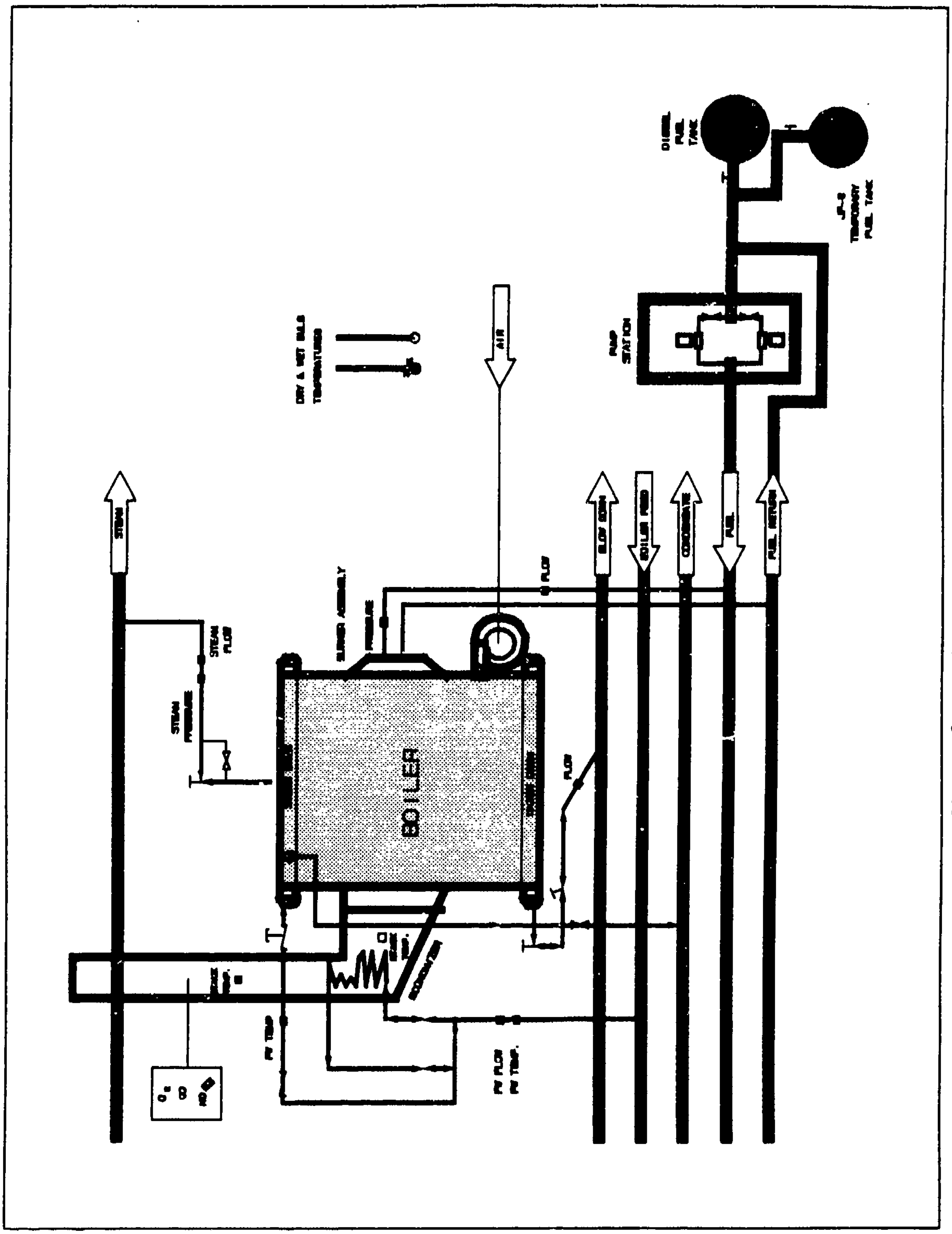


Figure 3. Full-scale Test Assembly

SECTION IV

EXPERIMENTAL TESTING PROGRAM

A. GENERAL

The performance of JP-8 was compared against diesel fuel and #2 fuel oil in the small-scale test and diesel fuel in the full-scale test. JP-8 was burned at the baseline air-to-fuel ratio of the reference fuels before adjusting the settings to optimize its performance.

It was expected that minimum problems would be associated with burning JP-8 in traditional heating systems. Potential problem areas identified included: burner performance, pump performance with the lower lubricity JP-8, and decreased system capacity due to the lower heating value of JP-8.

B. SMALL-SCALE TEST

1. Objectives

The specific objectives of the small-scale test were as follows:

a. Determine system boiler thermal efficiency for #2 fuel oil, diesel, and JP-8 at 100 percent operating capacity.

b. Determine boiler capacity for the test fuels.

c. Evaluate fuel pump performance while operating on JP-8 by measuring pump power consumption and fuel delivery pressure.

d. Evaluate overall burner performance while operating on JP-8 by computing efficiencies indicating fuel atomization characteristics and recording combustion air requirements and fuel pressure.

e. Measure the environmentally significant combustion products and compare them between the test fuels: Particulate, NO_2, SO_2, CO, Polynuclear Aromatic Hydrocarbons (PAH), Dioxins and Furans, and gaseous organic species.

f. Determine the effects of liquid JP-8 on the materials of fuel lines, storage tank, fuel pumps, and burner atomizing nozzle.

g. Determine the effects of JP-8 combustion products on the materials of boiler tubes, boiler walls, and flue walls.

2. Operation

The above objectives were met through a small-scale test plan that (1) compared the performance of JP-8 to diesel and #2 fuel oil under matched operating conditions for a total of 16 hours each, (2) optimized the performance of JP-8 with respect to boiler capacity, and (3) conducted a 200-hour performance test with JP-8 under optimized conditions.

During all tests, the system was operated for a period of at least one hour to reach steady-state before starting data collection. Data on system temperature, pressures, flow rates, relative humidity, and stack oxygen and carbon monoxide content were collected every 5 minutes during the experimental runs. Recorded information points can be seen in Figure 1, as indicated by "P" for pressure, "T" for temperature, and "F" for flow.

Baseline tests were performed on diesel, #2 fuel oil, and JP-8 with the boiler operating under full load with continuous firing. Results of the fuel analysis for the fuels used in the small-scale test are available in Appendix D. Boiler pressure was maintained at 5 psig, fuel pump pressure kept constant at 100 psig, and inlet air flow remained unchanged.

During JP-8 optimization the flow of fuel to the boiler was increased to the calculated rate required to match the boiler capacity of #2 fuel oil (see Appendix F, paragraph B). Fuel flow was increased by increasing the pump discharge pressure to 120 psig versus the baseline setting of 100 psig. The air flow was increased until there were no visible stack emissions. JP-8 was then burned in the small-scale boiler for 200 hours with one interruption in operation, due to atmospheric corrosion on a control wire.

3. Operational Results

The results of the small-scale test are summarized in Table 2, with data sheets available in Appendix E, description of method of analysis available in Appendix F, and the results of the analysis in Appendix G. Boiler efficiency calculations were made using the input-output method (14), with boiler thermal efficiency defined as the ratio of the heat absorbed by the boiler feedwater (boiler capacity) to the thermal energy input associated with the fuel, (refer to Appendix F, Equation F-1). Boiler capacity is also provided as steam output per gallon of fuel, which allows comparison on a cost basis.

TABLE 2. SMALL-SCALE TEST OPERATIONAL RESULTS

PROPERTIES	BASELINE			PERFORMANCE
	#2 OIL	DIESEL 2	JP-8	JP-8
STACK TEMP (°F)	562	566	545	567
STEAM FLOW (CFM)	50.0	48.0	45.0	58.0
STEAM TEMP (°F)	229	229	231	225
CONDENS. TEMP (°F)	204	205	197	211
FUEL PUMP PRESSURE (PSIG)	100	100	100	120
FUEL FLOW (GPH)	1.40	1.40	1.36	1.46
FUEL HEATING VALUE (BTU/GAL)	140,300	140,180	126,466	126,466
THERMAL ENERGY INPUT (BTU/HR)	196,400	196,300	171,900	184,900
BOILER CAPACITY (BTU/HR)	151,000	143,000	140,000	162,000
BOILER EFFICIENCY (%)	77.0	73.0	81.6	87.5
BOILER CAPACITY (BTU/GAL OF FUEL)	108,000	102,000	103,000	111,000
STACK O_2 (%)	8.9	10.0	10.3	6.3
STACK CO (PPM)	NEGL	NEGL	NEGL	NEGL

Testing revealed higher boiler thermal efficiencies with JP-8 versus #2 fuel oil and diesel. Although a 9.9 percent decrease in boiler capacity is expected because of the lower heating value of JP-8 (126,466 Btu/gal) versus that of #2 fuel oil (140,300 Btu/gal), boiler capacity experienced only a 7.3 percent drop with baseline JP-8 versus #2 fuel oil. When comparing baseline JP-8 with baseline diesel (fuel heating value of 140,180 Btu/gal), boiler capacity drop was only 2.2 percent versus the expected 9.8 percent. The performance of JP-8 at the higher flow rate showed an even higher boiler efficiency of 87.5 percent, resulting in a higher boiler capacity with the optimized JP-8 run versus the #2 fuel oil. When comparing boiler capacity per gallon of fuel, the results indicate that the tested boiler can achieve the same boiler capacity per gallon of fuel whether operating on #2 fuel oil or JP-8 and that JP-8 has the potential to outperform diesel.

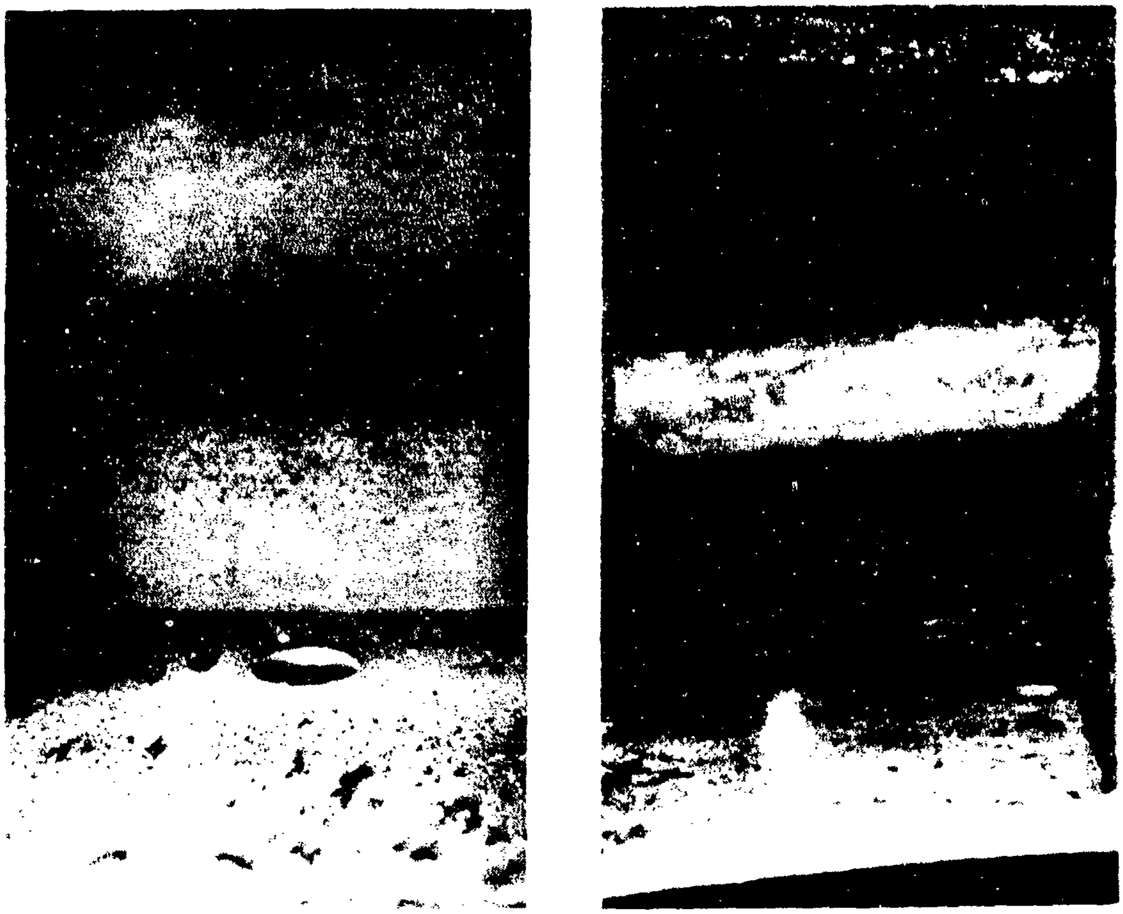
The burner fuel pump was designed to operate with kerosene based fuels and did not experience a decrease in fuel delivery pressure when operating with the lower viscosity JP-8. As a comparison, the recirculation Webster pump was continually operated with diesel and with JP-8, for a duration of 24 hours each. Test results show that the pump experienced a 2 percent drop in pressure when operating with JP-8 versus diesel.

The burner appeared to perform well with JP-8. Visual observation of the flame during the three fuel operations showed a cleaner, brighter, and tighter flame for JP-8 than for #2 fuel oil and diesel. The higher efficiencies and reduced soot buildup with JP-8 operations can be attributed to better atomization of the fuel. After 200 hours of continuously burning JP-8, the burner was removed and its nozzle was visually checked. No deterioration in the nozzle material or shape was observable.

Effects of liquid JP-8 on the fuel delivery system and burner were undetectable with respect to the lines, pumps, storage tank, and burner atomizing nozzle. The system did experience significant fuel line leakage at several junctions. This problem was solved by tightening the system at those points. Line leakage was expected due to the lower viscosity of JP-8 with respect to diesel and #2 fuel oil.

At the completion of the diesel and #2 fuel oil runs, the tubes were cleaned to allow comparison with JP-8. Soot buildup with the diesel and #2 fuel oil exceeded the JP-8 buildup significantly (i.e., approximately 1/16 inch buildup with diesel and #2 fuel oil versus no buildup with JP-8, 16 hours operation each). Figure 4 compares the soot buildup with diesel versus that with JP-8.

The system experienced no observable degradation in materials due to combustion products. Slight surface rust on the tubes was observed after the JP-8 run. This was attributed to the lack of a protective soot coating and the corrosive seaside environment. Tube and box material analysis was not possible due to planned reuse of system.



#2 Oil/Diesel JP-8

Figure 4: Small-scale Soot Buildup

4. Environmental Results

Stack samples were collected during each of the baseline tests to determine the NO_x, SO_x, organics, and particulate content of the boiler exhaust. Stack sampling techniques and data analysis methods are described in Appendix H.

The results of the environmental portion of the tests are summarized in Table 3. Environmental stack sampling revealed lower NO_x and SO_x emissions with JP-8 versus diesel and #2 fuel oil. Particulate data were inconclusive with the testing method chosen. All of the organics sampling events were compromised by burner flame-out during sample collection. The samples contained sizeable organic concentrations, but there was evidence that they were artifacts and not typical boiler emissions.

TABLE 3. SMALL-SCALE TEST EMISSION RESULTS

PROPERTIES	BASELINE			PERFORMANCE
	#2 OIL	DIESEL 2	JP-8	JP-8
EXCESS O_2 (%)	8.9	10.0	20.3	6.3
CO (PPM)	NEGL	NEGL	NEGL	NEGL
SO_2 (PPM)	90	50	26	13
NO_2 (PPM)	110	92	105	69
PARTICULATE (PPM)	2	5	2	25
ORGANICS	N/A	N/A	N/A	N/A

Small-scale testing indicated that safe, efficient operation with JP-8 as a boiler fuel was possible in the test boiler. Testing in a full-scale boiler was required to accurately determine the operational and environmental effects associated with burning JP-8 in traditional AF heating plant boilers.

Environmental results indicated the need for a certified emissions contractor. Factors making the certified contractor desirable included the non-portable nature of the equipment used to sample emissions during small-scale testing, the requirement to perform several emission collection methods at the same time, and the desire for the full-scale results to be considered valid by California state authorities.

C. FULL-SCALE TEST

1. Objectives

The specific objectives of the full-scale test were as follows:

a. Determine boiler thermal efficiency for diesel fuel (DF-2), JP-8 at DF-2 settings, and JP-8 at boiler performance settings at 100 percent operating capacity.

b. Determine boiler combustion efficiency for the three test conditions at 100 percent operating capacity.

c. Determine heating system thermal capacity for the three test conditions at 100 percent operating capacity.

d. Evaluate fuel pump performance while operating on JP-8 by measuring discharge pressure.

e. Evaluate overall burner performance (for both steam and air atomizing conditions) for all three test conditions: by computing efficiencies indicating atomization characteristics, number of soot blowouts required, number of burner change outs required, and capability of combustion at low turndown rates.

f. Measure the environmentally significant combustion products and compare them between the test fuels: Particulate, NO_x, SO_x, CO, and gaseous organic species.

g. Determine the effects of liquid JP-8 on the materials of fuel lines, burner's atomizing nozzle, automatic oil valve, oil train, and solenoid valves.

h. Determine the effects of JP-8 combustion products on the combustion chamber.

i. Evaluate flame pattern: flame shape and impingement, flame signal, and flame drop out rate using infrared signal.

Baseline testing was performed on diesel and JP-8 at set fuel/air ratios. Testing was performed according to the ASME Power Test Code for Steam Generating Units (14) for five load settings: 20, 40, 60, 80, and 100 percent. Data was collected for one hour each for the 20, 40, 60, and 80 percent load settings, with separate runs made for both steam and air atomization operations.

The fuel to air ratio was then adjusted to optimize the performance of JP-8 for the full range of boiler operation. This performance optimization was conducted by the boiler operator, in accordance with his normal adjustment procedures, with the goal of minimizing excess air (maximizing combustion efficiency) for the full range of the boiler along with maximizing the operating range itself. Power Test Code testing was duplicated with these JP-8 performance settings, with one hour test runs for the 20, 40, 60, and 80 percent load settings for both steam and air atomization operations.

100 percent load testing was scheduled for all three operating conditions at the end of the test period to facilitate efficient use of the contracted emissions personnel. Data was collected for a total of three one hour blocks for each of the fuel conditions at 100 percent load, steam atomization.

In addition to specific load testing, the boiler was operated following base load conditions for an additional 36 hours for the performance JP-8 test and the two baseline settings.

2. Test Schedule

The testing schedule was arranged to minimize the duration of the entire test, but ensure thorough evaluation, as shown in Table 4:

TABLE 4. FULL-SCALE TEST SCHEDULE

DATE	START TIME/ COMPL TIME	FUEL	LOAD SETTING	ATOMIZING AGENT
5/22/91	1015	DIESEL	20%	STEAM
	1125	DIESEL	40%	STEAM
	1235	DIESEL	60%	STEAM
	1325	DIESEL	80%	STEAM
	1425	DIESEL	20%	AIR
	1545	DIESEL	40%	AIR
	1635	DIESEL	60%	AIR
	1735	DIESEL	80%	AIR
	1900	DIESEL	MET LOAD	STEAM
5/23/91		DIESEL	MET LOAD	STEAM
5/24/91	COMPL 1330	DIESEL	MET LOAD	STEAM
5/25/91		BOILER COOL DOWN		
5/26/91		BOILER TUBE INSPECTION		
5/27/91		NO ACTIVITY		
5/28/91	0805	JP-8 BASELINE	20%	STEAM
	0925	JP-8 BASELINE	40%	STEAM
	1040	JP-8 BASELINE	60%	STEAM
	1155	JP-8 BASELINE	80%	STEAM
	1310	JP-8 BASELINE	20%	AIR
	1430	JP-8 BASELINE	40%	AIR
	1545	JP-8 BASELINE	60%	AIR
	1700	JP-8 BASELINE	80%	AIR

TABLE 4. FULL-SCALE TEST SCHEDULE (cont)

DATE	START TIME/ COMPL TIME	FUEL	LOAD SETTING	ATOMIZING AGENT
5/28/91	1830	JP-8 BASELINE	MET LOAD	STEAM
5/29/91		JP-8 BASELINE	MET LOAD	STEAM
5/30/91	COMPL 0830	JP-8 BASELINE	MET LOAD	STEAM
5/31/91	0700	BOILER TUBE INSPECTION/ OPTIMIZED FUEL:AIR RATIO FOR JP-8		
6/1/91	0700	JP-8 PERFORMANCE	20%	STEAM
	0815	JP-8 PERFORMANCE	40%	STEAM
	0930	JP-8 PERFORMANCE	60%	STEAM
	1050	JP-8 PERFORMANCE	80%	STEAM
	1210	JP-8 PERFORMANCE	20%	AIR
	1325	JP-8 PERFORMANCE	40%	AIR
	1520	JP-8 PERFORMANCE	60%	AIR
	1640	JP-8 PERFORMANCE	80%	AIR
	1800	JP-8 PERFORMANCE	MET LOAD	STEAM
6/2/91	COMPL 2400	JP-8 PERFORMANCE	MET LOAD	STEAM
6/3/91		BOILER TUBE INSPECTION		
	1145	JP-8 PERFORMANCE	100%	AIR
6/4/91		EMISSION CONTRACTOR NO SHOW		
6/5/91	1210-1310 1ST SAMPLE 1345-1445 2ND SAMPLE 1525-1625 3RD SAMPLE	JP-8 PERFORMANCE	100%	STEAM
	1650	JP-8 PERFORMANCE	100%	AIR

TABLE 4. FULL-SCALE TEST SCHEDULE (cont)

DATE	START TIME/ COMPL TIME	FUEL	LOAD SETTING	ATOMIZING AGENT
6/6/91	0745-0845 1ST SAMPLE 0910-1010 2ND SAMPLE 1035-1135 3RD SAMPLE	JP-8 BASELINE	100%	STEAM
	1210-1310 1ST SAMPLE 1345-1445 2ND SAMPLE 1510-1610 3RD SAMPLE	DIESEL BASELINE	100%	STEAM
	1610	TESTING COMPLETED		

3. Operation

The objectives of the full-scale test (Section IV.C.1.) were met through a test plan that compared the performance of the boiler with JP-8 to that with diesel. As noted in the schedule above, testing was accomplished with diesel at baseline conditions, then JP-8 at those same conditions before the boiler operator optimized the burner fuel-to-air settings (JP-8 performance) to maximize the boiler operating range and minimize O_2 levels.

Data on temperatures, pressures, flow rates, moisture content of the air, and stack O_2, CO, and NO_x content were collected and logged manually on a data sheet every 10 minutes during specific load testing and every 30 minutes when following demand. Results of the fuel elemental analysis for the diesel and the JP-8 used in the full-scale test are available in Appendix I. Information points can be seen on Figure 3 and recorded data are summarized in Appendix J. The data sheets are not included in this report due to the bulk of information collected. This information is available from HQ AFCESA/RACO upon request.

Additional data were collected on the skin temperature of the boiler at several points, flame characteristics, and fuel effects on the fuel line and auxiliary equipment.

Diesel baseline conditions were established prior to testing and were based on the ability to allow quick transition from natural gas as the primary fuel to diesel as the backup fuel without readjustment. JP-8 baseline data were collected for these same settings.

The switch from diesel to JP-8 was made by closing the fuel supply line from the diesel tank and opening the fuel supply line from the temporary JP-8 tank. It took approximately 10 minutes to flush the diesel before burning straight JP-8. The system did not falter with the introduction of the aviation fuel, but exhibited a tighter, brighter flame without any adjustment in fuel rate, air ratio, steam atomizing flow, or differential pressure between the atomizing steam pressure and the fuel pressure.

The performance of JP-8 was optimized to realize optimum combustion (minimum stack O_2 and minimum CO) throughout all firing ranges and maximize the operating range of the boiler. The process of making the adjustments on this single point burner (fuel and air were directly proportional to one another, with no O_2 trim) were as follows:

a. checked to see if there was sufficient air at the lowest power setting

b. maximized the burner output at 100 percent load

c. adjusted the burner to minimize O_2 and CO levels

d. verified max output by checking steam output and feedwater flow rates

e. tuned the fuel to be proportional with the steam flow throughout all of the firing ranges in 5 percent increments (air followed fuel flow due to single point control)

4. Operational Results

A comparison of the collected data and calculated efficiencies for the baseline runs and performance JP-8 at 100 percent load with steam atomization is provided in Table 5. The stack temperature remained basically the same for all three conditions at 314-315°F at the economizer exit. Calculated boiler efficiencies (input-output method), 100 percent load, are within the range of 78.2 to 81.8 percent, with baseline JP-8 showing the highest efficiency, and diesel the lowest. Stack O_2 is at a minimum with the performance JP-8 settings, and highest (5.3 percent) with baseline JP-8. The calculated combustion efficiencies reflect this, with JP-8 performance having the highest combustion efficiency at 88.36 percent, diesel basically the same, with 88.32 percent, and JP-8 baseline the lowest efficiency, at 87.33 percent. The 100 percent load calculations are the average of three hours worth of data collection. Our confidence level in this data is quite high, due to minimum variation among the data points.

TABLE 5. FULL-SCALE TEST OPERATIONAL RESULTS FOR 100% LOADS

PROPERTIES	BASELINE		PERFORMANCE
	DIESEL 2	JP-8	JP-8
STACK TEMP (°F)	314	315	314
STEAM FLOW (PPH)	20,400	20,100	20,400
STEAM PRESSURE (PSIG)	126	124	125
FEEDWATER TEMPERATURE (°F)	210	209	212
FUEL PUMP PRESSURE (PSIG)	101	98	100
FUEL FLOW (GPH)	188	196	202
FUEL HEATING VALUE (BTU/GAL)	140,720	127,885	127,885
THERMAL ENERGY INPUT (BTU/HR)	$26.4\ 10^6$	$25.0\ 10^6$	$25.9\ 10^6$
BOILER CAPACITY (BTU/HR)	$20.7\ 10^6$	$20.5\ 10^6$	$20.6\ 10^6$
BOILER EFFICIENCY (%)	78.2	81.8	79.8
BOILER CAPACITY (BTU/GAL OF FUEL)	110,000	105,000	102,000
COMBUSTION EFFICIENCY (%)	88.82	87.33	88.36
STACK O_2 (%)	4.70	5.30	3.40
STACK CO (PPM)	1.30	1.95	9.00

The calculated combustion efficiencies (Appendix J) vary significantly from the calculated boiler efficiencies. These combustion efficiencies include stack losses (dry gas, hydrogen, and CO_2), and water in the air. While the boiler efficiencies also include losses due to radiation, blow down loss, and soot losses.

Stack O_2 and CO reflect the change in settings for the performance JP-8 runs. The higher CO content with performance JP-8 indicates a slight increase in unburned combustibles.

The estimated manufacturer boiler efficiency (Figure 2) at 100 percent load (25,000 lb/hr, 125 psig steam, 139,784 Btu/gal, 10 percent excess air) is 86.5 percent. This efficiency differs from the observed 100 percent diesel run (20,400 lb/hr, 126 psig, 140,720 Btu/gal, 28 percent excess air) by 8.3 percent. This difference can be attributed in part (approximately 2 percent) to the excess air conditions in the diesel run, the difference in fuels, and that the boiler has been traditionally operating with decreased output compared to capacity.

Testing revealed higher boiler and combustion efficiencies with JP-8 versus diesel (refer to Figures 5 and 6), at the higher range of boiler load. Adjustments to optimize the performance of JP-8 resulted in a lower measured boiler efficiency with performance JP-8 than the baseline JP-8 at this higher range.

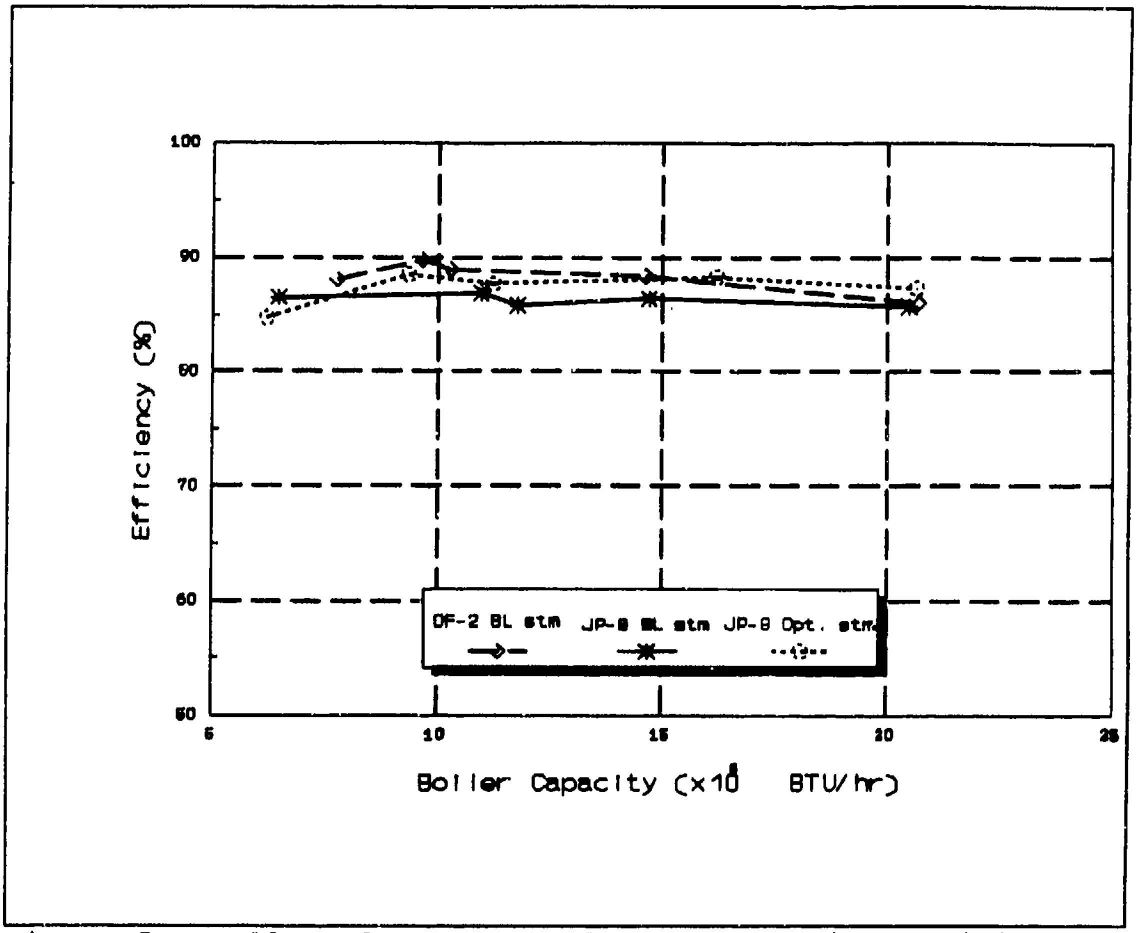


Figure 5. Full-scale Test Results: Combustion Efficiency

Figure 6 shows that performance JP-8 is steady over the full operating range, versus the fluctuation experienced with the baseline conditions. Both Figures 5 and 6 show a pronounced variation in efficiency, particularly in the range below 10.0 10^6 Btu/hr. This point is representative of this proportionally controlled unit (that is, single point control with air following fuel). The system is at optimum excess air at or close to this point. At loads below this point, stack O_2 will be higher, above this point it should stabilize. This concept is reflected in Figure 7, which shows the O_2 content with respect to boiler load.

The data reflected in Figures 5, 6, 7, and 8 for the data points at 20, 40, 60, and 80 percent loads are the average of a single hours worth of data collection, for each point. The pronounced dip in the efficiency curve for diesel in Figure 6 is unusual and indicates a potential problem with the steam flow measurement or with the performance of the system as a whole when operating with diesel. For this reason it is important to concentrate on the 100 percent load results when comparing the capabilities of JP-8 with respect to DF-2 in this full-scale test.

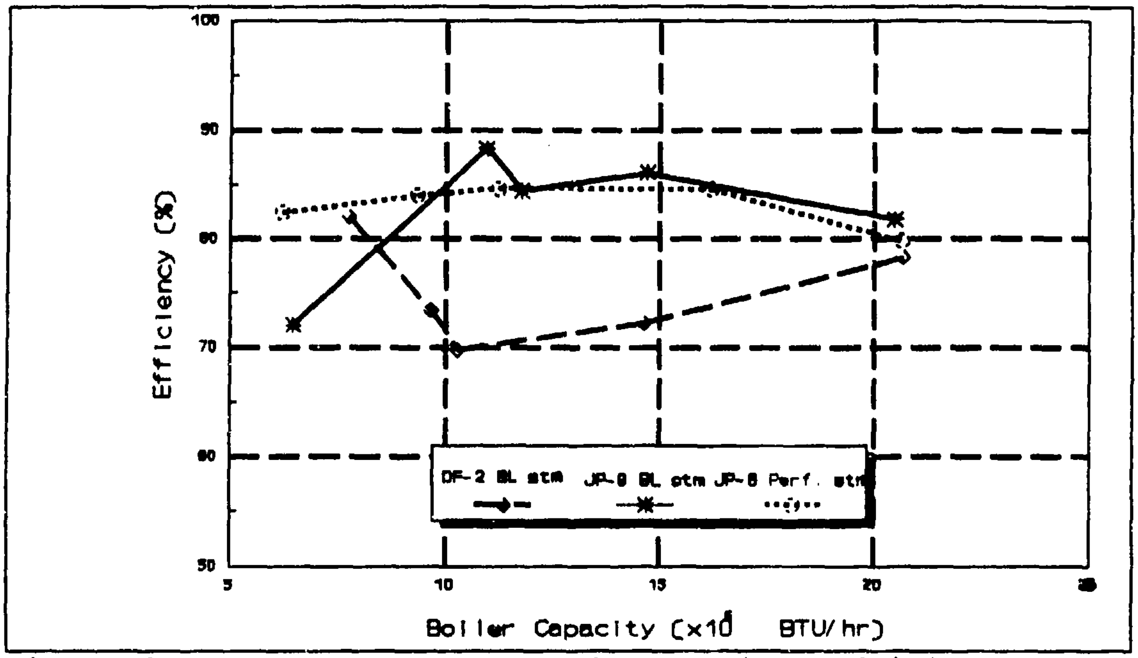


Figure 6. Full-scale Test Results: Boiler Efficiency

Figure 8 shows capacity with respect to fuel flow rate. A theoretical drop in boiler capacity of 9.1 percent was predicted with JP-8 operation due to the difference in fuel heating value between the diesel (140,720 Btu/gal) and the JP-8 (127,885 Btu/gal). Testing revealed a much smaller drop in boiler capacity. At 100 percent, the system showed a capacity drop of 4.5 percent at baseline JP-8 conditions and 7.2 percent at performance JP-8 conditions.

Test data and analyses for those tests run with air as the atomizing agent are available in Appendix J. A copy of all data collected is available from HQ AFCESA/RACO upon request.

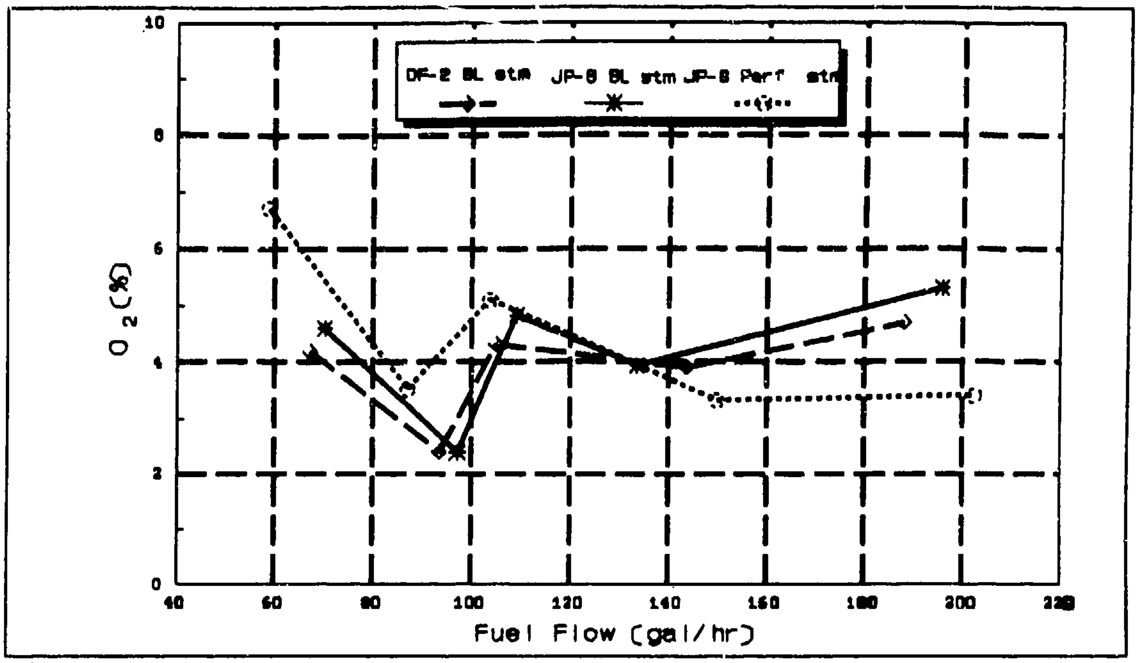


Figure 7. Full-scale Test Results: Stack O_2

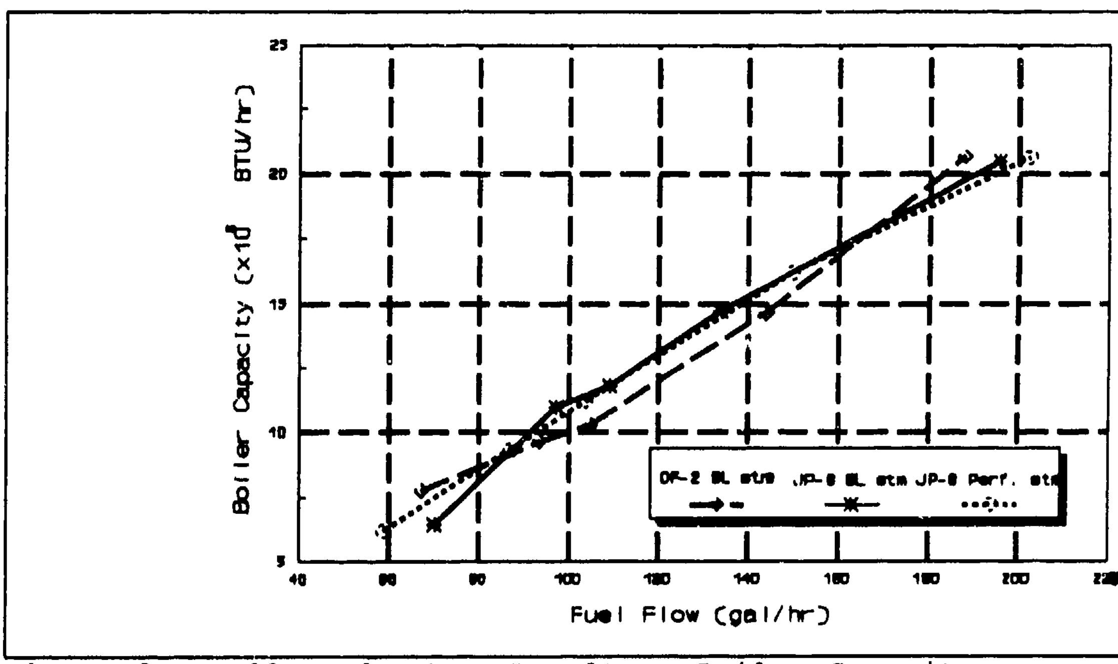


Figure 8. Full-scale Test Results: Boiler Capacity

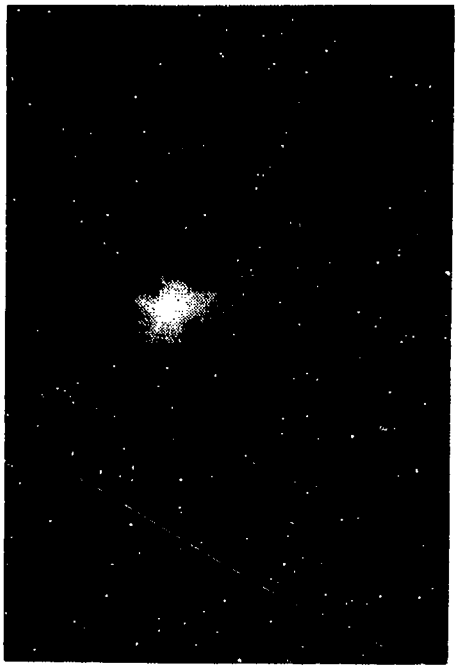
We experienced minimal pressure drop (3 percent) in the two fuel supply pumps. These pumps, vintage 1940 and 1960, have a rated capacity of 160 psig and 90 psig, respectively. The larger capacity pump experienced a gasket failure after 28 hours of operation on JP-8, but operator experience attributes this to dry rot of the gasket rather than a function of JP-8 operation. No further pump problems were noted during the remaining 70 hours of JP-8 operation.

The burner did not experience unusual problems when operating with JP-8. Photographs were taken of the flame during each of the load settings and visual observations were recorded. Examples of the JP-8 and diesel baseline flame shapes can be seen in Figure 9. Operation with JP-8 resulted in a more distinct flame that appeared to burn in a larger area of the fire box.

Diesel operations required soot blowouts at four different times during the 48-hour test. Stack temperatures with JP-8 did not indicate a need for soot blowouts during its operation. Similarly, there was buildup on the burner tip at the completion of the diesel run, whereas no evidence of buildup was seen after burning JP-8. As shown in Figure 8, the system was able to operate at low turn down rates for all three operating conditions.

Fuel line leakage was minimal; field test preparation which installed a temporary tank and connecting line stressed avoidance of this potential problem. During testing there was a persistent leak at one of the fuel pumps and periodic leaking at the fuel pressure line. The pump leak originated with diesel testing.

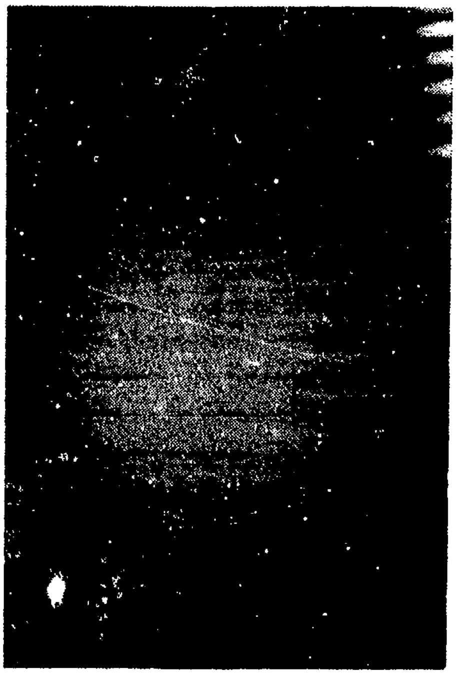
Soot buildup with JP-8 performance versus diesel was negligible. After 48 hours of operation with JP-8 there was an insufficient amount to collect for analysis. In comparison, soot buildup after diesel combustion was approximately 1/16 inch thick over the majority of the firebox. Figure 10 shows the difference in the soot buildup in the firebox when running with JP-8 versus diesel after 48 hours.



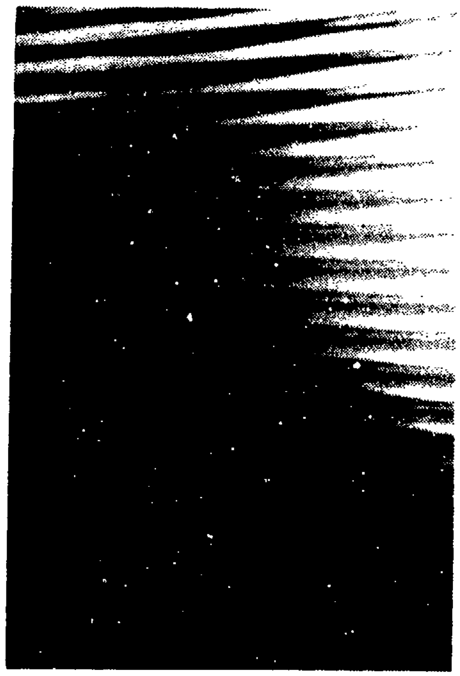
Diesel

JP-8 Performance

Figure 9. Full-scale Test : Flame Shape



Diesel



JP-8

Figure 10. Full-scale Test : Soot Buildup

Flame characteristics were evaluated by photographing the flame from each view port for each test run, recording visual observation of the flame shape and intensity, and recording the infrared signal reading (Tables 6 and 7 below).

TABLE 6. FULL-SCALE TEST FLAME INTENSITY (STEAM ATOMIZING)

TEST CONDITION	INTENSITY (mvDC)				
LOAD	20%	40%	60%	80%	100%
DIESEL BASELINE	19	19	19	20	20
JP-8 BASELINE	20	20	20	20	20
JP-8 PERFORMANCE	20	20	20	19	21

TABLE 7. FULL-SCALE TEST FLAME INTENSITY (AIR ATOMIZING)

TEST CONDITION	INTENSITY (mvDC)				
LOAD	20%	40%	60%	80%	100%
DIESEL BASELINE	20	21	19	18	-
JP-8 BASELINE	19.5	20	20	20	-
JP-8 PERFORMANCE	20.5	20	20.5	19	20

The following additional tests were added based on operations advice:

a. flame drop-out rate: the burner tip was pulled from the firebox and time before loss of flame was recorded

b. load response time: measured time for boiler pressure to increase from 100 psig to 120 psig with blocked steam flow

c. skin temperatures were recorded to calculate radiation losses and observe differences in firebox temperatures

The results of the above tests are summarized in Tables 8 and 9.

TABLE 8. FULL-SCALE TEST OPERATIONS TEST RESULTS

TEST	DIESEL BASELINE	JP-8 BASELINE	JP-8 PERFORMANCE
LOAD RESPONSE TIME			
1ST TEST	1:40.46	2:17.70	3:05.78
2ND TEST	1:39.62	2:46.22	3:08.39
3RD TEST	1:38.82	2:31.07	3:17.53
AVERAGE	1:39.63	2:31.66	3:10.57

The flame drop-out rate showed negligible differences in the fuel test conditions.

Skin temperatures were measured on the exterior of the firebox at nine different positions as shown in Figure 11. Measurements were made with an Exergen D-Sensries Microscanner™ provided by the Corp of Engineers Civil Engineering Research Laboratory.

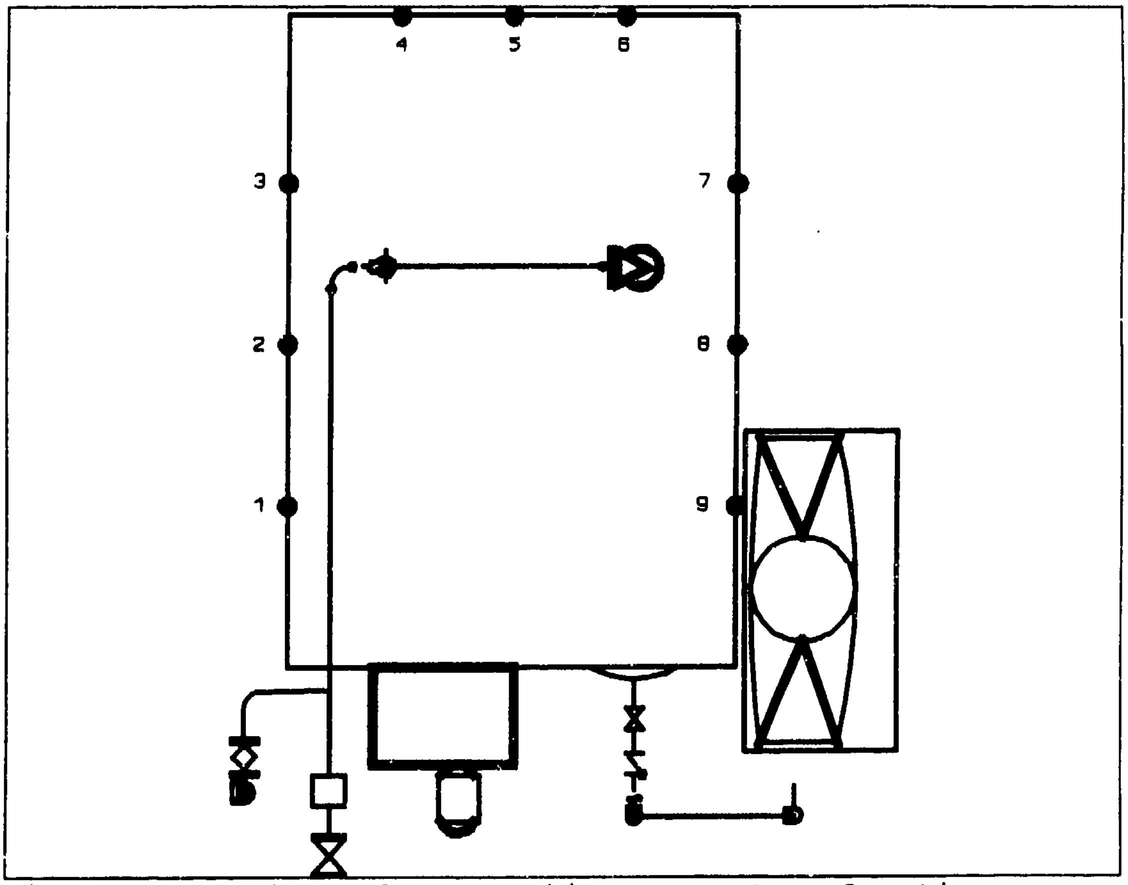


Figure 11. Full-scale Test Skin Temperature Locations

TABLE 9. FULL-SCALE TEST SKIN TEMPERATURES

TEST CONDITION	POSITION °F								
	1	2	3	4	5	6	7	8	9
DF2 LOAD ST	171	110	108	217	235	174	109	110	124
DF2 100% ST	172	115	113	223	234	148	110	113	133
JP8B 40% ST	142	99	99	81	101	98	91	92	111
JP8B 60% ST	146	104	103	120	134	88	95	96	111
JP8B 80% ST	151	104	105	135	158	99	98	100	119
JP8B 100% ST	152	102	102	175	203	129	95	99	117
JP8B 20% AIR	155	109	109	150	173	109	104	104	121
JP8B 40% AIR	163	114	112	161	169	117	106	107	121
JP8B 60% AIR	131	114	112	168	180	124	110	110	125
JP8B 80% AIR	167	115	115	178	194	130	109	111	132
JP8B 100% A	152	102	105	185	155	127	99	101	120
JP8B LOAD ST	157	101	102	212	223	155	100	103	125
JP8P 20% ST	146	99	97	118	124	111	92	95	103
JP8P 40% ST	154	108	106	127	136	115	102	105	119
JP8P 60% ST	165	113	112	140	154	121	109	113	127
JP8P 80% ST	167	117	117	153	173	127	112	116	133
JP8P 100% S	172	120	118	195	224	135	115	116	135
JP8P 20% A	168	115	114	115	169	126	111	112	128
JP8P 40% A	168	118	115	161	171	129	112	112	127
JP8P 60% A	171	120	117	173	184	136	113	114	130
JP8P 80% A	174	121	119	181	197	141	115	116	136
JP8P 100% A	172	116	118	126	237	157	118	122	141
JP8P LOAD S	165	106	105	196	219	156	101	103	119

5. Environmental Results

Stack data were collected for NO_x, SO_x, particulate, and organics. The results of the nonorganic analysis is shown in Table 10 and the organic analysis in Table 11. Sampling methodology and reported results for particulate, SO_x, and NO_x are included as Appendix K, organics documentation is available in Appendix L.

Baseline JP-8 conditions resulted in significantly lower particulate, NO_x, and SO_x emissions than the measured diesel emissions. Carbon monoxide emission readings were approximately the same. JP-8 performance conditions resulted in comparable SO_x emissions to the baseline JP-8 conditions, but particulate and NO_x emission were closer the baseline diesel emissions. The NO_x profiles for the three operating conditions are shown in Figure 12. Both of the JP-8 conditions resulted in much lower SO_x emissions than the diesel runs.

TABLE 10. FULL-SCALE TEST INORGANIC STACK EMISSION RESULTS

CONSTITUENT	DIESEL BASE. (AVG)	JP-8 BASE. (AVG)	JP-8 PERFORM. (AVG)
TOTAL PARTICULATE (EPA)			
gr/DSCF	0.0078	0.0036	0.0070
gr/DSCF @12% CO_2	0.0074	0.0122	0.0065
lb/hr	0.40	0.19	0.34
TOTAL PARTICULATE (CARB)			
gr/DSCF	0.0170	0.0078	0.0129
gr/DSCF @12% CO_2	0.0165	0.0077	0.0120
lb/hr	0.90	0.42	0.63
OXIDE OF NITROGEN			
ppmv	65	52	61
ppmv @3% O_2	70	57	62
lb/hr	2.89	2.39	2.63
SULFUR DIOXIDE			
ppmv	92	<1	2
ppmv @3% O_2	99	<1	2
lb/hr	5.67	<0.07	0.14
CARBON MONOXIDE			
ppmv	<1	<1	4
ppmv @3% O_2	<1	<1	4
lb/hr	<0.03	<0.03	0.11

TABLE 11. FULL-SCALE TEST ORGANIC STACK EMISSION RESULTS

Sample	Concentration (g/liter) (Avg)
Diesel Baseline	0.029
JP-8 Baseline	0.035
JP-8 Performance	0.033

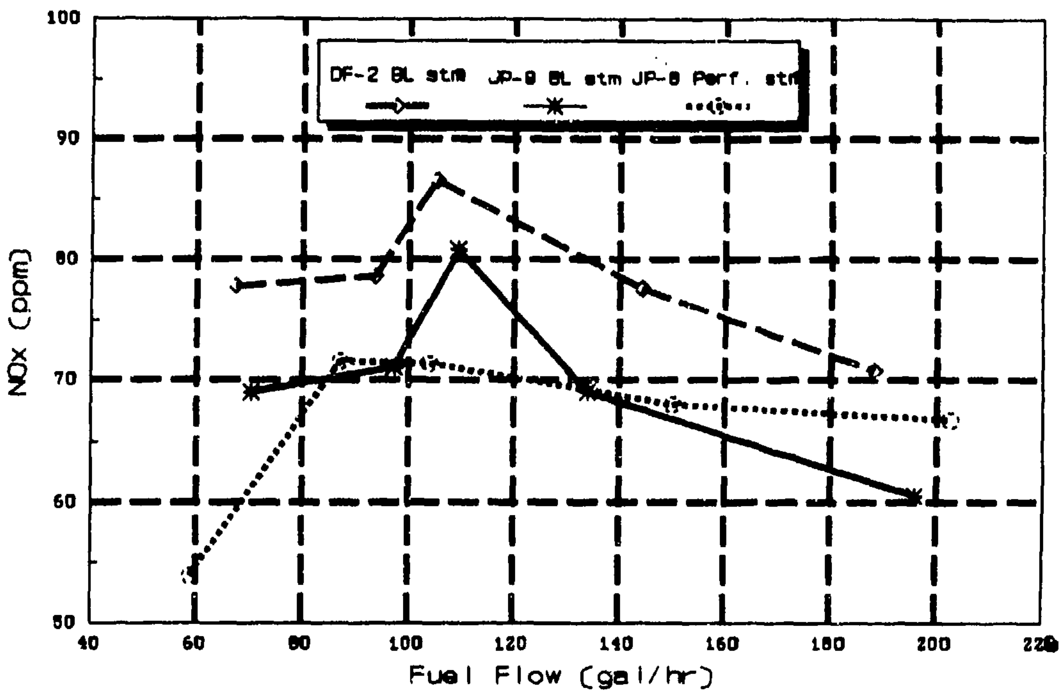


Figure 12. Full-scale Test Results: NO_x Emissions

SECTION V

DISCUSSION

The results of these tests demonstrate that JP-8 can be an effective fuel for boiler combustion. Boiler capacities and efficiencies were satisfactory when operating with JP-8 in comparison to diesel and #2 fuel oil. The results also showed a reduction in emission output of SO_x, NO_x, and particulate when burning JP-8 instead of diesel or #2 fuel oil.

A. SYSTEMS MODIFICATIONS

The full-scale system successfully transitioned from burning diesel to burning JP-8 with no modifications to the fuel-air-ratio and other system parameters. To enable optimum performance of the boiler with JP-8, the following adjustments should be considered:

1. An increase in the differential between the atomizing steam or air pressure and the fuel pressure, over that established for either diesel or #2 fuel oil, will aid in better atomization of JP-8. This modification was suggested by the burner manufacturer's literature to compensate for a difference in viscosities. The full-scale performance JP-8 test increased this differential from 20 psig to 30 psig.

2. Transport fuel pump exit pressures may decrease up to 3 percent, based on the difference in fuel viscosities. Boiler systems that are dependent on the delivery pressure from a fuel pump rather than the pump on their burner unit, may be affected by this difference. Fuel pumps that cannot be adjusted to compensate for this reduction in fuel delivery pressure and reduced fuel flow will have to be replaced if original boiler capacity is required.

3. Pump performance, fuel lines, and auxiliary equipment should be monitored closely during fuel conversion and subsequent operation. There is a potential for leakage when switching from one type of fuel to another. The potential is even greater due to the lower viscosity of JP-8 with respect to diesel or #2 fuel oil.

4. Transition to explosion proof wiring and fixtures is not mandatory with conversion to JP-8. The minimum flashpoint specification for JP-8 is identical to #2 fuel oil (refer to Table 1).

B. OPERATIONS MODIFICATIONS

Normal boiler safety and operations procedures must be followed when burning JP-8 in heating plant boilers. Guidance concerning the operation of JP-8, based on full-scale testing includes:

1. Adjustments will have to be made to the burner to optimize

fuel performance. No adjustments should be necessary to the burner management system or to the safety control circuit.

2. A decrease in maintenance requirements is expected due to the cleaner burning qualities of JP-8, both in the liquid and combustion phases. Increasing stack temperatures were not evident (Appendix J) during JP-8 testing, and fewer soot blowouts were required.

C. BOILER PERFORMANCE

As discussed briefly in Section IV, the full-scale boiler exhibited unusual performance in the regime below 40 percent load for all three test conditions. This performance is attributed to low firing fuel-to-air ratios and fuel flow at low loads. The burner/boiler arrangement has an excess air break point at 40% load. At around the 20% manual load point, the fuel feed rate is accelerated beyond the manual set point to ensure sufficient fuel for light off. Evidence of the excess fuel flow rate can be seen in the low stack oxygen content for all three test conditions at this point (Figure 7) and in the erratic boiler efficiency curve (Figures 6).

The data reflected in Figures 5, 6, 7, and 8 for the data points at 20, 40, 60, and 80 percent loads reflect the average of a single hour of data collection, for each point. The pronounced dip in the efficiency curve for diesel in Figure 6 is unusual and indicates a potential problem with the steam flow measurement or with the system as a whole when operating with diesel. For this reason it is important to concentrate on the 100 percent load results when comparing the capabilities of JP-8 with respect to DF-2 in this full-scale test.

Review of boiler performance for 40 to 100 percent loads revealed excellent performance on the part of JP-8 at both the baseline and performance conditions (Figure 8). Though the combustion efficiency of diesel at 100 percent load matched that of JP-8 optimized, diesel had higher skin temperatures, resulting in a higher radiation loss, and showed a significant buildup in soot, yet another loss. These two losses were not included in the combustion efficiency calculation. A higher stack O_2 content with the JP-8 baseline run impacted the combustion efficiency.

The capacity of the full-scale boiler was reduced when operating with JP-8 at the same fuel flow rate as diesel. Measured boiler capacity per gallon of fuel (Table 5) was 110,000 Btu/Gal for DF-2, 105,000 Btu/Gal for baseline JP-8, and 102,000 Btu/Gal for performance JP-8. Small-scale results (Table 2) were somewhat different with DF-2 at 102,000 Btu/Gal, JP-8 baseline at 103,000 Btu/Gal, and performance JP-8 at 111,000 Btu/Gal. This variation in capacity is consistent with engine tests performed by the Army (1), which showed a range of outputs.

Based on the full-scale results, a decrease in boiler capacity per gal of fuel can be expected when burning JP-8. System adjustments (fuel pressure, fuel/atomization medium differential pressure, and fuel-to-air ratio) will improve the range of the boiler and the output when operating with JP-8.

The tests showed a successful burn of JP-8 in existing boilers with no modifications to the burners. Several burner and boiler manufactures suggested the development of a specific burner to maximize the fuel properties of JP-8 and achieve optimum combustion. This development may become prudent in light of recent energy constraints.

D. STACK EMISSIONS

Stack emissions resulting from burning JP-8 were lower in NO_x, SO_x, and particulate than stack content when burning DF-2. The State of Florida has no limit for NO_x for boilers less than 250 mmBtu/hr and depends on fuel content for SO_x (full-scale results showed diesel at 5.67 lb/hr and JP-8 at 0.14 lb/hr), particulate is not measured, but there is a restriction on the opacity measurement (20%). Opacities were close to zero for all runs made (refer to Appendix J). The opacity measurements for the 100% runs are inaccurate due to outside light transmission during the emissions collection performed by BTC Environmental Incorporated and HQ AFCESA/RAV. The difference in the organics content of the three full-scale test runs at 100 percent boiler load, steam atomization, were negligible.

E. ADDITIONAL BENEFITS

This effort has shown that JP-8 is a viable boiler fuel; this supports the concept of operation with a single supplied fuel in the PACAF arena. A preliminary investigation by the Belvoir Fuels and Lubricants Research Facility (SwRI) in conjunction with the U.S. Army Belvoir Research, Development and Engineering Center Materials, Fuels and Lubricants Laboratory (3) predicts several benefits associated with a switch from diesel to JP-8 fuel in military ground vehicles. Many of them are applicable to JP-8 use in military boilers. Predicted benefits include:

1. Greater low-temperature operability with JP-8 versus diesel or #2 fuel oil:

a. the lower freezing point of JP-8 (-47°C) versus that of diesel* indicates that JP-8 should eliminate fuel flow problems down to -47°C. Low temperature problems include filter plugging, failure to pump, screen waxing and the associated startability problems. In comparison, use of DF-2 could cause problems at temperatures as a high as 30°F, while DF-A, with a cloud-point specification maximum of -51°C, would perform better than JP-8 in extremely cold weather conditions.

b. because of the lower freeze point of JP-8 and antiwaxing tendencies, JP-8 will require tank and fuel line heating systems at only the coldest of locations. This results in both an operational energy savings and purchased equipment savings.

2. Cleaner fuel:

a. reduced sulfur

b. particulate contamination is limited to 1.0 mg/L for JP-8, whereas federal requirements allows up to 10 mg/L of particulate matter for all grades of diesel fuel

3. Fuel efficiency and performance: projected fuel efficiency on a per volume basis is less than for diesel.

4. All aspects of fuel production, procurement, handling, storage, and use will be affected by reducing the types of fuel supplied from three--gasoline, diesel (or fuel oils), and jet--to one fuel (JP-8). Reductions in personnel and/or cost can be expected as follows (2):

a. reduce the number of personnel to oversee the procurement activity: maintenance requirement for multiple fuel specifications, waivers of fuel property deviations will decline since the specification for JP-8 is inflexible, number of laboratory tests required to procure the fuel will decline since only one specification must be met, accounting systems will be simpler, combined tankage capability with a single fuel, eliminate pockets of unusable fuel, and increased readiness.

b. JP-4 requires vapor control systems during storage and transfer to reduce the evaporation of rate JP-4 into the atmosphere. These systems prevent pollution of the environment and significant fuel losses, but at a heavy cost. These costs can

* The cloud point of DF-2 can range from -20° to 30°F. The cloud-point and freeze-point tests (ADTM D 2500 and D 2386, respectively) measure different fuel properties, but the numbers are often close and typically do not vary more than 10 degrees F from one another.

range from $200,000 to $2,000,000 depending on the size and system type. JP-8, with a lower vapor pressure does not require vapor control systems nor storage tanks with floating roofs or floating pans to prevent evaporation.

SECTION VI

CONCLUSIONS AND RECOMMENDATIONS

JP-8 has been found to be an effective fuel for boiler combustion. The operational performance of JP-8 in comparison with DF-2 and #2 fuel oil was satisfactory, with fuel to steam conversion ranging from 7 percent less with JP-8 to performance that exceeded that of #2 fuel oil and DF-2.

Stack emissions showed a significant drop in SO_x with JP-8, and lower values of NO_x and particulate. There was negligible difference between the organics measurements among the three full-scale test conditions.

Normal boiler safety and operations procedures must be followed because of the lower flashpoint of JP-8. Pump performance, fuel lines, and auxiliary equipment should be monitored closely during fuel conversion and subsequent operation.

The following operational guidance concerning the use of JP-8 in heating plant boilers, based on full-scale testing, is recommended:

a. A supervisory management controller with a mandatory purge cycle and low fire start is highly recommended. The mandatory purge cycle and low fire start should be verified by either contact closure on the quadrant or positioning motor before the management system allows a trial for ignition. The inclusion of this system will ensure safe start-ups, reliability, and eliminate human error.

b. Trained and experienced boiler operations personnel should supervise air/fuel adjustments associated with JP-8, as with any fuel.

c. The system could expect a drop in fuel pump delivery pressure of up to 3 percent, based on the difference in fuel viscosities. Fuel pumps that cannot be adjusted to compensate for this reduction in fuel delivery pressure and reduced fuel flow will have to be replaced if the operation or capacity of the boiler is dependent on this delivery pressure.

Neither rotary cup burners nor fire-tube type boilers were tested in this program. It can be expected that JP-8 will exhibit similar operational characteristics with these types of equipment, as with those tested.

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APPENDIX A

MILITARY REQUIREMENTS FOR DF-2, #2 FUEL OIL, JP-8, JP-5, AND JP-4 FUEL PROPERTIES (6,7,8,9)

TABLE A-1. FUEL PROPERTIES

PROPERTY*	DF-2	#2 FUEL OIL	JP-8	JP-5	JP-4
Color, Saybolt			Report only	Report only	Report only
Total Acid #, mg KOH/g, max	-		0.015	0.015	0.015
Aromatics, vol %, max	30		25.0	25.0	25.0
Olefins, vol %, max			5.0	5.0	5.0
Mercaptan sulfur, wt%, max			0.001	0.001	0.001
Sulfur, total wt%, max	0.28	1.0	0.30	0.40	0.40
Distill. C(F) Init. boiling pt	187(369)		Report only	Report only	Report only
10% recovered	217(423)		205(401) max	205(401) max	Report only
20% recovered			Report only	Report only	145(293) max
50% recovered	263(505)		Report only	Report only	190(374) max
90% recovered	314(597)	338(640)	Report only	Report only	245(518) max
End point	345(653)		300(572) max	290(554) max	270(518) max
Residue, vol%, max			1.5	1.5	1.5
Distil.loss vol%, max			1.5	1.5	1.5

PROPERTY*	DF-2	#2 FUEL OIL	JP-8	JP-5	JP-4
Explosive. %, max			-	50	no rqmt
Flashpoint, C(F), min	64(147)	38 (100)	38 (100)	60 (140)	no rqmt
Gravity, max API (min sp gr) at 15.6C (60F)			37.0 (0.840)	36.0 (0.845)	45.0 (0.806)
Gravity, min API (max sp gr) at 15.6C (60F)			51.0 (0.775)	48.0 (0.788)	57.0 (0.751)
Vapor pres., kPa (psi) at 37.8C (100F) max			no rqmt	no rqmt	21 (3.0)
Vapor pres., kPa (psi) at 149C (300F) max			no rqmt	no rqmt	no rqmt
Vapor pres., kPa (psi) at 260C (500F) max			no rqmt	no rqmt	no rqmt
Freezing pt C, (F), max			-50 (-58)	-46(-51)	-58(-72)
Viscosity at -20C (-4F), cSt, max	@40C 2.65		8.0	8.5	no rqmt
Net heat of combustion, MJ/kg (Btu/lb) min			42.8 (18,400)	42.6 (18,300)	42.8 (18,400)

PROPERTY*	DF-2	#2 FUEL OIL	JP-8	JP-5	JP-4
Combustion Properties:					
Luminometer #, min			no rqmt	no rqmt	no rqmt
Smoke pt, min			19.0	19.0	20.0
Napthalenes vol, max, %			no rqmt	no rqmt	no rqmt
H_2 content, mass %, min			13.5	13.5	13.6
Cu strip corrosion, 100C (212F), max			1b	1b	1b
Thermal Stability: JFTOT, Temp resid.time, F/min			500/150	500/150	500/150
Change in pres. drop, mm HG, max			25	25	25
Preheater Deposit code, max			<3	<3	<3
TDR Spun, max			no rqmt	no rqmt	no rqmt
Existent gum, mg/100 mL, max			7.0	7.0	7.0
Particulate matter>0.8 umg/L, max			1.0	1.0	1.0
Filtration time (min), max			no rqmt	15	10
Water rxn interface rating			1b	1b	1b

PROPERTY*	DF-2	#2 FUEL OIL	JP-8	JP-5	JP-4
Water separ.index mod., min			-	-	-
Icing inhibitor (FSII),vol%			0.10 to 0.15	0.15 to 0.20	0.10 to 0.15
Electrical Conduct., pS/m			200 to 600	no rqmt	200 to 600
Thermal precip. rating, max			no rqmt	no rqmt	no rqmt
Peroxide number, mEq/kg, max			no rqmt	1.0	no rqmt

* When the field is blank, a value is not specified

APPENDIX B

PACAF BOILER, BURNER, AND FUEL PUMP INVENTORY

The following information is provided to present a sampling of the boiler, burner, and fuel pump inventory in the Air Force. It summarizes information submitted by the installations into the Central Heating Plant Database developed by the Civil Engineering Research Laboratory (Army Corps of Engineers) for the U.S. Air Force. Additional information was requested and provided by the air bases specifically for this project. Several data fields and units of measure are described in further detail below:

Design Pressure	psig
Operating Pressure	psig
Design Capacity	million British Thermal Unit (MBtu) (rounded to two decimal places, i.e., 002.15 MBtu)
Rated Capacity	MBtu, rounded to two decimal places
Des Fuel	Design Fuel
Pri Fuel	Primary Fuel
Sec Fuel	Secondary Fuel
Dist Media	S=steam, H=high temperature water, L=low temperature water

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Andersen AB	01091	01	0150	0015	001.00	001.00	DF2	DF2	JP8	S	1963	Fire Tube Scotch Marine	Power Master
Andersen AB	25010	01	0100	0040	001.70	001.70	DF2	DF2	JP8	S	1954	Dry Back	Gabriel
Andersen AB	25010	02	0150	0040	002.50	002.50	DF2	DF2	JP8	S	1989	Fire Tube Scotch Marine	Cleaver Brooks
Andersen AB	26006	01	0125	0015	001.20	001.20	DF2	DF2	JP8	S	1971	Fire Tube Scotch Marine	Highlander
Andersen AB	[illegible]	01	0100	0012	000.14	000.14	DF2	DF2	JP8	L	1982	Cast Iron	Ray Burner
Andersen AB	[illegible]	01	0100	[illegible]	000.14	000.14	DF2	DF2	JP8	L	1982	Cast Iron	Ray Burner
Andersen AB	[illegible]	01	0100	[illegible]	000.14	000.14	DF2	DF2	JP8	L	1982	Cast Iron	Ray Burner
Andersen AB	27006	01	0100	[illegible]	[illegible]	000.14	DF2	DF2	JP8	L	1982	Cast Iron	Ray Burner
Andersen AB	00032	01	0100	[illegible]	[illegible]	[illegible]	DF2	DF2	JP8	L	1975	Fire Tube Scotch Marine	Cleaver-Brooks
Andersen AB	00032	01	0100	[illegible]	[illegible]	001.20	DF2	DF2	JP8	L	1975	Fire Tube Scotch Marine	Cleaver-Brooks

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	FUEL PUMP MODEL NO.
Andersen AB	01091	01	SPA	POWER MASTER	5L	WEBSTER	08582R213D-508
Andersen AB	25010	01	SPA	CLEAVER BROOKS	M100-60	WEBSTER	08582R213D-598
Andersen AB	25010	02	SPA	CLEAVER BROOKS	M100-60	WEBSTER	2R121D-508
Andersen AB	26006	01	SPA	INDUST. COMB	30	WEBSTER	39429
Andersen AB	27000	01	SPA	RAY BURNER	JPE SIZE 0	WEBSTER	0585-2R213D-508
Andersen AB	27001	01	SPA	RAY BURNER	JPE SIZE 0	SUNSTRAND	H3BAB200H
Andersen AB	27003	01	SPA	RAY BURNER	JPE SIZE 0	SUNTEC	#4+LIGHTER
Andersen AB	27006	01	SPA	RAY BURNER	JPE SIZE 0	SUNSTRAND	H3BAB200H
Andersen AB	00032	01	SPA	Cleaver Brooks	CBH100-30	SUNSTRAND	J4PB100-3
Andersen AB	00032	01	SPA	Cleaver Brooks	CBH100-30	WEBSTER	2R213D-508

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Wickam AFB	00422	01	0015	0013	001.34	001.11	DF2	DF2		S	1988	Water Tube	Rite Engineering
Wickam AFB	00559	01	0150	0040	001.17	001.13	DF2	DF2		S	1988	Water Tube	Cleaver-Brooks
Wickam AFB	00559	02	0150	0040	001.17	001.13	DF2	DF2		S	1975	Water Tube	Cleaver-Brooks
Wickam AFB	00906	01	0250	0040	001.17	001.50	DF2	DF2		S	1987	Water Tube	Cleaver-Brooks
Wickam AFB	00906	02	0150	0040	001.00	001.01	DF2	DF2		S	1977	Fire Tube	York-Shipley
Wickam AFB	01860	01	0015	0013	001.34	001.26	DF2	DF2		S	1968	Fire Tube	Cleaver-Brooks
Wickam AFB	01860	02	0015	0013	001.34	001.26	DF2	DF2		S	1968	Fire Tube	Cleaver-Brooks
Wickam AFB	02010	01	0125	0040	000.54	000.54	DF2	DF2		S	1989	Water Tube	York-Shipley

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	FUEL PUMP MODEL NO.
Wickam AFB	00422	01	S.P.	Gordon-Paiti	R8-G-05	Sunstrand	----
Wickam AFB	00559	01	S.P.	C.B.M4HP	1500 200	Webster	2R626C
Wickam AFB	00559	02	S.P.	C.B.M4HP	1500 200	Webster	2R626C
Wickam AFB	00906	01	S.P.	C.B.M4P	2000 Ser.100	Webster	2R626C
Wickam AFB	00906	02	S.P.	C.B.M4P	2000 Ser.100	Webster	2R626C
Wickam AFB	01860	01	S.P.	C.B.CBM-40	2000 Ser.100	Suntec	M
Wickam AFB	01860	02	S.P.	C.B.CBM-40	2000 Ser.100	Sunstrand	M
Wickam AFB	02010	01	S.P.	Wayne Home Div.	EM	Sunstrand	M
Wickam AFB	1738	Incinerator	SPA	Wayne	EM	Suntec	M
Wickam AFB	12 ea.	Water Heaters	OIL	Wayne	361E	Sunstrand	M

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Kadena AB	00109	01	0030	0020	002.50	002.50	DFM	DFM	JP8	L	1986	Cast Iron	Showa
Kadena AB	00313	01	0050	0038	002.50	002.50	DFM	DFM	JP8	S	1953	Fire Tube	Kewanee
Kadena AB	00320	01	0000	0000	000.00	000.00	DFM	DFM	JP8	S	1959	Fire Tube	Gabriel
Kadena AB	02957	02	0030	0020	002.90	002.90	DFM	DFM	JP8	L	1980	Cast Iron	Showa
Kadena AB	03476	01	0030	0020	003.45	003.45	DFM	DFM	JP8	L	1960	Fire Tube	Kewanee
Kadena AB	03538	01	0030	0020	002.11	002.11	DFM	DFM	JP8	L	1960	Fire Tube	Gabriel
Kadena AB	06198	01	0030	0020	005.15	005.15	DFM	DFM	JP8	L	1983	Cast Iron	Showa
Kadena AB	09359	01	0030	0020	002.65	002.65	DFM	DFM	JP8	L	1988	Fire Tube Scotch	Kewanee
Kadena AB	09495	01	0030	0030	003.15	003.15	DFM	DFM	JP8	L	1983	Fire Tube Scotch	Edwards
Kadena AB	95002	01	0150	0025	006.69	006.69	DFM	DFM	JP8	S	1987	Fire Tube Scotch	York-Shipley

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	FUEL PUMP MODEL NO.
Kadena AB	00109	01	S.P.	Wayne Home Div	EH	SUNSTRAND	H
Kadena AB	00313	01	S.P.	Wayne Home Div	EH	SUNSTRAND	H
Kadena AB	00320	01	S.P.	Wayne Home Div	EH	SUNSTRAND	H
Kadena AB	02957	02	S.P.	Showa	EH	SUNSTRAND	H
Kadena AB	03476	01	S.P.	Showa	SH160	SUNSTRAND	H
Kadena AB	03538	01	S.P.	Showa	SH160	SUNSTRAND	H
Kadena AB	06198	01	S.P.	Showa	SH160	SUNSTRAND	H
Kadena AB	09359	01	S.P.	Showa	SH160	SUNSTRAND	H
Kadena AB	09495	01	S.P.	Showa	SH150	SUNSTRAND	H
Kadena AB	95002	01	S.P.	Showa	SH160	SUNSTRAND	H

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	FUEL PUMP MODEL NO.
Kadena	10180	01	S.P.	Kawasaki	KP-608-NWO	----	---
Kadena	10180	02	S.P.	Kawasaki	KP-608-NWO	----	---
Kadena	10210	01	S.P.	Kewanee Boiler Corp	KP-608-NWO	----	---
Kadena	10210	02	S.P.	Kawasaki	KP-608-NWO	----	---
Kadena	10257	02	S.P.	Kewanee Boiler Corp	KP-608-NWO	----	---
Kadena	10270	01	S.P.	Kawasaki	KP-608-NWO	----	---
Kadena	10270	02	S.P.	Kewanse Boiler Corp	KP-608-NWO	----	---
Kadena	10236	01	S.P.	Kawasaki	KP-608-NWO	----	---
Kadena	10236	02	S.P.	Kewanee Boiler Corp	KP-608-NWO	----	---
Kadena	10341	01	S.P.	Kewanee Boiler Corp	KF0.75-762-0	----	---
Kadena	10341	02	S.P.	Kewanee Boiler Corp	KF0.75-762-0	----	---
Kadena	1729	01	S.P.	Kewanee Boiler Corp	KF0.33-600-0	----	---
Kadena	1729	02	S.P.	Kewanee Boiler Corp	KF0.33-600-0	----	---
Kadena	1861	01	S.P.	Kewanee Boiler Corp	KF0.33-762-0	----	---
Kadena	1861	02	S.P.	Kewanee Boiler Corp	KF0.33-762-0	----	---
Kadena	2079	01	S.P.	Kewanee Boiler Corp	KF0.50-762-0	----	---
Kadena	2079	02	S.P.	Kewanee Boiler Corp	KF0.33-762-0	----	---
Kadena	2437	01	S.P.	ABC/Sunray	KF0.33-762-0	----	---
Kadena	2437	02	S.P.	ABC/Sunray	KF0.33-762-0	----	---
Kadena	02444	01	S.P.	Showa SA Boiler	SH-160	----	---
Kadena	02444	02	S.P.	Showa SA Boiler	SH-160	----	---
Kadena	02957	01	S.P.	Kewanee Boiler Corp	SH-160	----	---
Kadena	02986	01	S.P.	Kewanee Boiler Corp	KF0.33-762-0	----	---
Kadena	02986	02	S.P.	Kewanee Boiler Corp	KF0.33-762-0	----	---

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	MODEL NO.
Kedena	5009	01	S.P.	Aldrich	KF0.33-762-0	----	---
Kadena	5009	02	S.P.	Aldrich	KF0.33-762-0	----	---
Kadena	5452	01	S.P.	Kewanee	KF0.50-762-0	----	---
Kadena	5452	02	S.P.	Kewanee	KF0.50-762-0	----	---
Kadena	8111	01	S.P.	ABC/Sunray	KF0.50-762-0	----	---
Kadena	8111	02	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8145	01	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8145	02	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8147	01	S.P.	Federal Boiler Co.	"Nu-Way"	----	---
Kadena	8147	02	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8155	01	S.P.	Kewanee	KF0.33-762-0	----	---
Kadena	8155	02	S.P.	Kewanee	KF0.33-762-0	----	---
Kadena	8185	01	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8185	02	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8195	01	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8195	02	S.P.	Potterton Eden	"Nu-Way"	----	---
Kadena	8214	01	S.P.	Kewanee Boiler	KF0.33-600-0	----	---
Kadena	8214	02	S.F.	Kewanee Boiler	KF0.33-600-0	----	---
Kadena	9286	01	S.P.	Kewanee Boiler	KF0.33-762-0	----	---
Kadena	9286	02	S.P.	Showa	SN-160	----	---
Kadena	9325	01	S.P.	Kewanee	KF1.0-762-0	----	---
Kadena	9325	02	S.P.	Kewanee	KF1.0-762-0	----	---
Kadena	9359	02	S.P.	Kewanee	KF1.0-762-0	----	---
Kadena	9392	01	S.P.	Showa	SN-160	----	---
Kadena	9392	02	S.P.	Kewanee	KF1.0-762-0	----	---
Kadena	9476	01	S.P.	Kewanee	KF0.50-762-0	----	---
Kadena	9476	02	S.P.	Kawasaki	KP-608-NWO	----	---

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
King Salmon	00138	01	0030	0020	000.00	000.99	DFA	DFA		S	1988	Fire Tube	Weil McLain
King Salmon	00145	01	0015	0010	002.50	002.90	DFA	DFA		S	1957	Dry Back Scotch Marine	Dutton N.
King Salmon	00147	01	0030	0012	001.00	000.49	DFA	DFA		L	1969	Cast Iron	National
King Salmon	00149	01	0015	0010	001.00	000.46	DFA	DFA		S	1982	Fire Tube	Kewanee
King Salmon	00150	01	0030	0012	000.00	000.35	DFA	DFA		L	1988	Fire Tube	Weil McLain
King Salmon	00154	01	0030	0012	000.00	000.20	DFA	DFA		L	1986	Fire Tube	Weil McLain
King Salmon	00158	01	0030	0012	000.00	000.12	DFA	DFA		L	1989	Fire Tube	Weil McLain
King Salmon	00160	01	0015	0012	003.60	004.00	DFA	DFA		S	1955	Fire Tube	Pacific
King Salmon	00160	02	0015	0012	003.60	004.00	DFA	DFA		S	1955	Fire Tube	Pacific
King Salmon	00300	03	0015	0012	003.60	004.00	DFA	DFA		S	1955	Fire Tube	Pacific
King Salmon	00162	01	0015	0010	001.50	001.70	DFA	DFA		S	1955	Fire Tube	Birchfield
King Salmon	00300	01	0125	0012	000.00	003.60	DFA	DFA		L	1987	Fire Tube	Ajax
King Salmon	00638	01	0125	0060	003.80	002.27	DFA	DFA		S	1950	Fire Tube	Kewanee
King Salmon	00638	02	0125	0060	003.80	004.47	DFA	DFA		S	1950	Fire Tube	Kewanee
King Salmon	00638	03	0125	0060	003.80	004.47	DFA	DFA		S	1950	Fire Tube	Kewanee
King Salmon	00643	01	0030	0012	001.00	000.95	DFA	DFA		L	1984	Fire Tube	Weil McLain

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	MODEL NO.
King Salmon	00138	01	S.P.	Blue Angel	NS	Suntec	B2VA8216
King Salmon	00145	01	S.P.	Golden Cup	PHC 34	Sunstrand	H3PBNC2OGH4
King Salmon	00147	01	S.P.	American	93C-2	Suntec	J3BB1003
King Salmon	00149	01	S.P.	American	GC-3	Webster	2R111DSC1
King Salmon	00150	01	S.P.	Weil McLain	EN	Suntec	B2YA-8916
King Salmon	00154	01	S.P.	Weil McLain	NS-66	Suntec	A2VA7116
King Salmon	00158	01	S.P.	Blue Angel	NS	Suntec	B2VA8216
King Salmon	00160	01	R.C.	Ray or B. ARSP	101-550	Ray	550Size 3
King Salmon	00160	02	R.C.	Ray or B. ARSP	101-550	Ray	550Size 3
King Salmon	00300	03	R.C.	Ray or B. ARJP	101-551	Ray	550Size 3
King Salmon	00162	01	S.P.	Carun	701CRD	Ray	550Size 3
King Salmon	00300	01	S.P.	Power Flame	CR-3-0	Webster	22R32205AA14
King Salmon	00638	01	R.C.	Ray Oil ARJP	104	Ray	550Size 7
King Salmon	00638	02	R.C.	Ray Oil ARJP	104	Ray	550Size 7
King Salmon	00638	03	R.C.	Ray Oil ARJP	104	Ray	550Size 7
King Salmon	00643	01	S.P.	Weil McLain	WM-NS-66	Sunstrand	A2VA1116

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Kunsan AB	00387	01	0030	0025	000.94	000.81	DFW	DFW	JP8	L	1986	Fire Tube	Aldrich
Kunsan AB	00550	01	0015	0015	001.08	001.08	DFW	DFW	JP8	S	1984	Fire Tube	Aldrich
Kunsan AB	00550	02	0030	0025	001.08	001.08	DFW	DFW	JP8	L	1984	Fire Tube	Aldrich
Kunsan AB	00823	01	0030	0025	001.38	001.20	DFW	DFW	JP8	L	1985	Fire Tube Scotch Marine	Burnham
Kunsan AB	00823	02	0030	0025	001.38	001.20	DFW	DFW	JP8	L	1985	Fire Tube Scotch Marine	Burnham
Kunsan AB	01057	01	0015	0015	000.35	003.35	DFW	[illegible]	JP8	[illegible]	[illegible]	Fire Tube	Aldrich
Kunsan AB	01104	01	0015	0015	001.74	001.74	DFW	DFW	[illegible]	S	1985	Fire Tube	York-Shipley
Kunsan AB	01104	02	0015	0015	001.74	001.74	DFW	DFW	[illegible]	S	1995	Fire Tube	York-Shipley
Kunsan AB	01360	01	0150	0090	002.68	002.68	DFW	[illegible]	JP8	[illegible]	1968	Fire Tube	Burnham
Kunsan AB	01513	01	0030	0025	001.06	000.92	DFW	DFW	JP8	L	[illegible]	Fire Tube Scotch Marine	Burnham
Kunsan AB	02820	01	0015	0010	001.06	001.06	DFW	DFW	[illegible]	S	[illegible]	Fire Tube	Burnham
Kunsan AB	02850	01	0015	0010	001.00	001.00	DFW	DFW	[illegible]	S	[illegible]	Fire Tube	York-Shipley

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER
Kunsan AB	00387	01	SP	American	HC-3	Suntec
Kunsan AB	00550	01	SP	Wayne	FH	Sunstrand
Kunsan AB	00550	02	SP	Wayne	FH	Sunstrand
Kunsan AB	00823	01	SP	Carun	801CRD	Suntec
Kunsan AB	00823	02	SP	Carun	801CRD	Suntec
Kunsan AB	01057	01	SP	ABC Sunray	93C-Z	Suntec
Kunsan AB	01104	01	SP	Y.S.	FU-20	Suntec
Kunsan AB	01104	02	SP	Y.S.	FU-20	Suntec
Kunsan AB	01360	01	SP	Power Game	C3-0	Webster
Kunsan AB	01513	01	SP	Carlin	[illegible]	Suntec
Kunsan AB	02820	01	SP	Power Game	CR1-G	Webster
Kunsan AB	02850	01	SP	Power Game	CR1-0	Sunstrand

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Misawa AB	00465	01	0142	0085	053.35	055.00	DFW	DFW	JP8	S	1987	Water Tube	Takuma Co Ltd
Misawa AB	00465	02	0142	0085	053.35	055.00	DFW	DFW	JP8	S	1987	Water Tube	Takuma Co Ltd
Misawa AB	00465	03	0142	0085	053.35	055.00	DFW	DFW	JP8	S	1987	Water Tube	Takuma Co Ltd
Misawa AB	00465	04	0142	0085	030.75	031.70	DFW	DFW	JP8	S	1982	Water Tube	Takuma Co Ltd
Misawa AB	00465	05	0142	0085	017.07	017.07	DFW	DFW	JP8	S	1988	Fire Tube Scotch Marine	Takuma Co Ltd
Misawa AB	01337	03	0142	0055	006.43	006.62	DFW	DFW	JP8	S	1986	Fire Tube Scotch Marine	Takuma Co Ltd
Misawa AB	01337	04	0142	0070	015.40	015.40	DFW	DFW	JP8	S	1989	Fire Tube	Takuma Co Ltd
Misawa AB	01337	05	0142	0070	015.40	015.40	DFW	DFW	JP8	S	1989	Fire Tube	Takuma Co Ltd
Misawa AB	01573	01	0060	0035	008.37	008.63	DFW	DFW	JP8	S	1969	Fire Tube Scotch Marine	Cleaver-Brooks
Misawa AB	01573	02	0060	0035	008.37	008.63	DFW	DFW	JP8	S	1977	Fire Tube Scotch Marine	Cleaver-Brooks
Misawa AB	01948	01	0142	0070	020.53	022.05	DFW	DFW	JP8	S	1985	Fire Tube Scotch Marine	Kawaju Reynetsu Co
Misawa AB	01948	02	0142	0070	020.53	022.05	DFW	DFW	JP8	S	1985	Fire Tube Scotch Marine	Kawaju Reynetsu Co
Misawa AB	01948	04	0142	0070	025.67	017.64	DFW	DFW	JP8	S	1987	Fire Tube Scotch MAtine	Kawaju Reynetsu Co

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	FUEL PUMP MODEL NO.
Misawa AB	00465	01	S.A.	Takuma	U-65(CR1)NF212	Sunstrand	J3BA
Misawa AB	00465	02	S.A.	Takuma	U-65(CR1)NF212	Sunstrand	J3BA
Misawa AB	00465	03	S.A.	Takuma	U-65(CR1)NF212	Sunstrand	J3BA
Misawa AB	00465	04	S.A.	Takuma	85NF2MV	Sunstrand	J3BA
Misawa AB	00465	05	R.C.	Sunray	RBS 6.5	Sunstrand	J3BA
Misawa AB	01337	03	R.C.	-	-	Sunstrand	J3BA
Misawa AB	01337	04	R.C.	Sunray	RBS 6.5	Sunstrand	J3BA
Misawa AB	01337	05	R.C.	Sunray	RBS 6.5	Sunstrand	J3BA
Misawa AB	01573	01	R.C.	Cleaver Brooks	CB107-250	Sunstrand	J3BA
Misawa AB	01573	02	R.C.	Cleaver Crooks	CB100X-250	Sunstrand	J3BA
Misawa AB	01948	01	R.C.	Sunray	RBS 6.5	Sunstrand	J3BA
Misawa AB	01948	02	R.C.	Sunray	RBS 6.5	Sunstrand	J3BA
Misawa AB	01948	04	R.C.	Sunray	RB-10	Sunstrand	J3BA

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Osan AB	00733	01	0150	0015	001.33	000.00	DF2	DF2	JP8	S	1987	Fire Tube	Columbia
Osan AB	00733	02	0140	0002	001.33	000.00	DF2	DF2	JP8	S	1987	Fire Tube	Columbia
Osan AB	00777	01	0150	0075	010.04	000.00	DF2	DF2	JP8	S	1985	Fire Tube	York-Shipley
Osan AB	00777	02	0150	0075	010.04	000.00	DF2	DF2	JP8	S	1985	Fire Tube	York-Shipley
Osan AB	00782	01	0150	0015	002.00	000.00	DF2	DF2	JP8	S	1985	Fire Tube	Columbia
Osan AB	00846	01	0150	0040	002.10	000.00	DF2	DF2	JP8	S	1975	Fire Tube	Ray Burner
Osan AB	00846	02	0150	0040	002.10	000.00	DF2	DF2	JP8	S	1978	Fire Tube	Ray Burner
Osan AB	00846	03	0150	0040	002.10	000.00	DF2	DF2	JP8	S	1978	Fire Tube	Ray Burner
Osan AB	01737	01	0150	0040	001.67	000.00	DF2	DF2	JP8	S	1978	Fire Tube	York-Shipley
Osan AB	01737	02	0150	0040	001.67	000.00	DF2	DF2	JP8	S	1978	Fire Tube	York-Shipley
Osan AB	01737	03	0150	0040	001.67	000.00	DF2	DF2	JP8	S	1978	Fire Tube	York-Shipley
Osan AB	01750	01	0015	0015	005.02	000.00	DF2	DF2	JP8	S	1980	Fire Tube	York-Shipley
Osan AB	01750	02	0015	0015	005.02	000.00	DF2	DF2	JP8	S	1980	Fire Tube	York-Shipley

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	FUEL PUMP MODEL NO.
Osan AB	0342	01	S.P.A.	American Burner Corp	HC-3	Suntec	H
Osan AB	0342	02	S.P.A.	American Burner Corp	HC-3	Suntec	H
Osan AB	0533	01	S.P.A.	Kewanee Boiler Corp	KF-0-33-762-0	UL	728N
Osan AB	0630	01	S.P.A.	York-Shipley	NVB-1C	Suntec	H
Osan AB	0777	01	S.P.A.	York-Shipley	FV-100	Suntec	H
Osan AB	0793	01	S.P.A.	Kewanee	KF-0-33-600-0	UL	728N
Osan AB	0892	01	S.P.A.	York-Shipley	FV-20A	UL	728N
Osan AB	1185	01	S.P.A.	York-Shipley	FV-20A	Sunstrand	H
Osan AB	1186	01	S.P.A.	Bock	N-SK	Suntec	AZVA-7116
Osan AB	1326	01	S.P.A.	Bolden Corp	HC34	Sunstrand	H
Osan AB	1327	01	S.P.A.	Bolden Corp	HC34	Sunstrand	H
Osan AB	1343	01	S.P.A.	York-Shipley	F/20A2	Sunstrand	H
Osan AB	1343	02	S.P.A.	York-Shipley	NVB10	Sunstrand	H
Osan AB	1423	01	S.P.A.	Wayne	911193	UL	728N
Osan AB	1423	02	S.P.A.	Wayne	911193	UL	728N
Osan AB	1425	01	S.P.A.	Wayne	FH	?	?
Osan AB	1738	01	S.P.A.	Wayne	EH	Suntec	BZVA-8216
Osan AB	00733	01	S.P.A.	Carlin	801CRD	Suntec	H
Osan AB	00733	02	S.P.A.	Carlin	801CRD	Suntec	H
Osan AB	00777	01	S.P.A.	York-Ship	FY-100	Suntec	H
Osan AB	00777	02	S.P.A.	York-Ship	FY-100	Suntec	H
Osan AB	00782	01	S.P.A.	Carlin	801CRD	Suntec	H
Osan AB	00846	01	S.P.A.	Ray Burner	PDSF	Suntec	?
Osan AB	00846	02	S.P.A.	R.B.	PDSF	Suntec	?
Osan AB	00846	03	S.P.A.	R.B.	PDSF	Suntec	?
Osan AB	01737	01	S.P.A.	York Ship	FY-20AZ	Sunstrand	H
Osan AB	01737	02	S.P.A.	York Ship	FY-20AZ	Sunstrand	H
Osan AB	01737	03	S.P.A.	York Ship	FY-20AZ	UL	?
Osan AB	01750	01	S.P.A.	York Ship	FY-20AZ	UL	728N
Osan AB	01750	02	S.P.A.	York Ship	FY-20AZ	UL	728N

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Yokota AB	00009	01	0142	0100	033.45	000.00	FS1	FS1	JP8	S	1976	Water Tube	
Yokota AB	00009	04	0250	0100	016.73	016.73	FS1	FS1	JP8	S	1972	Water Tube	
Yokota AB	00009	05	0250	0100	01673	016.73	FS1	FS1	JP8	S	1972	Water Tube	
Yokota AB	00079	01	0070	0020	002.55	002.55	FS1	FS1	JP8	L	1984	Fire Tube	Showa
Yokota AB	00080	01	0070	0012	001.59	001.59	FS1	FS1	JP8	L	1979	Fire Tube	Takuma
Yokota AB	00614	01	0142	0100	025.76	025.76	FS1	FS1	JP8	S	1981	Water Tube	Takuma
Yokota AB	00614	02	0142	0100	033.45	033.45	FS1	FS1	JP8	S	1975	Water Tube	Takuma
Yokota AB	01245	01	0142	0100	140.14	140.14	FS1	FS1	JP8	S	1976	Water Tube	Takuma
Yokota AB	01245	02	0142	0100	025.80	025.80	FS1	FS1	JP8	S	1980	Water Tube	Takuma
Yokota AB	01245	03	0228	0100	016.73	016.73	FS1	FS1	JP8	S	1977	Water Tube	Takuma
Yokota AB	01509	01	0070	0012	000.99	000.99	FS1	FS1	JP8	L	1979	Fire Tube	Takuma
Yokota AB	04085	01	0142	0100	002.01	002.01	FS1	FS1	JP8	S	1977	Water Tube	Takuma
Yokota AB	04096	01	0228	0100	016.73	016.73	FS1	FS1	JP8	S	1975	Water Tube	Takuma
Yokota AB	04096	02	0228	0100	016.73	016.73	FS1	FS1	JP8	S	1975	Water Tube	Takuma
Yokota AB	04408	01	0142	0100	003.18	003.18	FS1	FS1	JP8	S	1986	Water Tube	Takuma
Yokota AB	04408	02	0142	0100	003.18	003.18	FS1	FS1	JP8	S	1986	Water Tube	Takuma
Yokota AB	04436	01	0228	0100	035.96	035.96	FS1	FS1	JP8	N	1973	Water Tube	Takuma
Yokota AB	04436	02	0228	0100	035.96	035.96	FS1	FS1	JP8	N	1972	Water Tube	Takuma
Yokota AB	04436	03	0228	0100	035.96	035.96	FS1	FS1	JP8	N	1972	Water Tube	Takuma
Yokota AB	04436	04	0228	0100	035.96	035.96	FS1	FS1	JP8	N	1977	Water Tube	Takuma

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	FUEL PUMP MODEL NO.
Yokota AB	00009	01	S.A.	Volcano	VS2-9-41	Kosaka	bN-2T-42
Yokota AB	00009	04	S.A.	P.E.C.	DN-345-24	Pacer	19217N-2E170
Yokota AB	00009	05	S.A.	P.E.C.	DN-345-24	Pacer	19217N-2E170
Yokota AB	00079	01	S.A.	P.E.C.	DN-345-24	Pacer	19217N-2E170
Yokota AB	00080	01	S.A.	P.E.C.	DN-345-24	Pacer	19217N-2E170
Yokota AB	00614	01	S.A.	Volcano	VSPP-650	Kawasaki	25-3N5DB
Yokota AB	00614	02	S.A.	Volcano	VS2-9-41	Kosaka	6N-2T-42
Yokota AB	01245	01	S.A.	Volcano	VS-2-20-41	Kocaka	6T-2T-47
Yokota AB	01245	02	S.A.	Volcano	VSPP-650	Kawasaki	25-3N5DB
Yokota AB	01245	03	S.A.	NKF COEN	J-4410NF	Kawasaki	25-3N5DB
Yokota AB	01509	01	S.A.	NKF COEN	J-4410NF	Kawasaki	25-3N5DB
Yokota AB	04085	01	S.A.	NKF COEN	J-4410NF	Kawasaki	25-3N5DB
Yokota AB	04096	01	S.A.	NKF COEN	J-4410NF	Kawasaki	25-6N5D
Yokota AB	04096	02	S.A.	NKF COEN	J-4410NF	Kawasaki	25-6N5D
Yokota AB	04408	01	S.A.	NKF COEN	J-4410NF	Kawasaki	25-6N5D
Yokota AB	04408	02	S.A.	NKF COEN	J-4410NF	Kawasaki	25-6N5D
Yokota AB	04436	01	R.C.	Ray Oil	BbE-1000	Ray	D54/1600
Yokota AB	04436	02	R.C.	Ray Oil	BbE-1000	Ray	D54/1600
Yokota AB	04436	03	R.C.	Ray Oil	BbE-1000	Ray	D54/1600
Yokota AB	04436	04	R.C.	Ray Oil	BbE-1000	Ray	D54/1600

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Cape Lisburne	00151	01	0150	0060	008.30	008.30	DFS	DFA		S	1969	Fire Tube Scotch Marine	Cleaver Brooks
Cape Lisburne	00151	02	0150	0060	008.30	008.30	DFS	DFA		S	1969	Fire Tube Scotch Marine	Cleaver Brooks
Cape Lisburne	00151	03	0150	0060	008.30	008.30	DFS	DFA		S	1969	Fire Tube Scotch Marine	Cleaver Brooks
Cape Romanzof	00002	01	0000	0000	001.40	000.00					0000	Water Tube	Cleaver Brooks
Cape Romanzof	00002	02	0000	0000	001.40	000.00					0000	Water Tube	Cleaver Brooks
Cape Romanzof	02232	01	0000	0000	003.80	000.00					0000	Fire Tube Firebox	
Cape Romanzof	02232	02	0000	0000	003.80	000.00					0000	Fire Tube Firebox	
Cape Romanzof	02232	03	0000	0000	003.80	000.00					0000	Fire Tube Firebox	
Eielson	00002	01	0000	0000	001.70	000.00					0000	Fire Tube Firebox	
Eielson	00000	02	0000	0000	001.70	000.00					0000	Fire Tube Firebox	
Eielson	00000	03	0000	0000	001.70	000.00					0000	Fire Tube Firebox	
Eielson	06203	01	0425	0400	160.00	133.50	COL	COL		S	1951	Water Tube	Springfield
Eielson	06203	02	0425	0400	160.00	133.50	COL	COL		S	1951	Water Tube	
Eielson	06203	03	0425	0400	160.00	133.50	COL	COL		S	1951	Water Tube	Springfield
Eielson	06203	04	0425	0400	160.00	133.50	COL	COL		S	1951	Water Tube	Springfield
Eielson	06203	05	0425	0400	160.00	133.50	COL	COL		S	1954	Water Tube	Garrett & Shafer
Eielson	06203	06	0425	0400	160.00	133.50	COL	COL		S	1954	Water Tube	Garrett & Shafer

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	MODEL NO.
Cape Lisburne	00151	01	-	-	-	-	-
Cape Lisburne	00151	02	-	-	-	-	-
Cape Lisburne	00151	03	-	-	-	-	-
Cape Romanzof	00002	01	-	-	-	-	-
Cape Romanzof	00002	02	-	-	-	-	-
Cape Romanzof	02232	01	-	-	-	-	-
Cape Romanzof	02232	02	-	-	-	-	-
Cape Romanzof	02232	03	-	-	-	-	-
Eielson	00002	01	-	-	-	-	-
Eielson	00000	02	-	-	-	-	-
Eielson	00000	03	-	-	-	-	-
Eielson	06203	01	-	-	-	-	-
Eielson	06203	02	-	-	-	-	-
Eielson	06203	03	-	-	-	-	-
Eielson	06203	04	-	-	-	-	-
Eielson	06203	05	-	-	-	-	-
Eielson	06203	06	-	-	-	-	-

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Elmendorf	00000	01	0000	0000	002.10	000.00					1970	Fire Tube Scotch Marine	
Elmendorf	00000	02	0000	0000	001.70	000.00					1970	Fire Tube Scotch Marine	
Elmendorf	00000	03	0000	0000	001.70	000.00					1970	Fire Tube Scotch Marine	
Elmendorf	22004	01	0490	0415	229.19	208.35	COL	NAG	DFA	S	1954	Water Tube	Erie City
Elmendorf	22004	02	0490	0415	229.19	208.35	COL	NAG	DFA	S	1954	Water Tube	Erie City
Elmendorf	22004	03	0490	0415	229.19	208.35	COL	NAG	DFA	S	1954	Water Tube	Erie City
Elmendorf	22004	04	0490	0415	229.19	208.35	COL	NAG	DFA	S	1954	Water Tube	Erie City
Elmendorf	22004	05	0490	0415	229.19	208.35	COL	NAG	DFA	S	1954	Water Tube	Erie City
Elmendorf	22004	06	0490	0415	229.19	208.35	COL	NAG	DFA	S	1954	Water Tube	Erie City
Elmendorf	24805	01	0160	0110	010.00	000.00	DFM	NAG	DFA	S	1952	Water Tube	Superior
Elmendorf	24805	02	0160	0110	010.00	000.00	DFM	NAG	DFA	S	1952	Water Tube	Superior
Elmendorf	24805	03	0160	0110	010.00	000.00	DFM	NAG	DFA	S	1952	Water Tube	Superior
Elmendorf	33322	01	0015	0012	000.40	000.00	DFM	DFA	N/A	S	1961	Fire Tube Firebox	Birchfield
Elmendorf	33324	01	0015	0012	000.40	000.00	DFM	DFA	N/A	S	1961	Fire Tube	Birchfield
Elmendorf	41155	01	0000	0000	004.50	000.00				S	1954	Fire Tube Firebox	
Elmendorf	41755	01	0050	0030	002.00	002.25	DFM	NAG	DFA	S	1988	Water Tube	NB Smith
Elmendorf	41755	02	0050	0030	002.00	002.25	DFM	NAG	DFA	W	1988	Water Tube	NB Smith
Elmendorf	41755	03	0050	0030	002.00	002.25	DFM	NAG	DFA	W	1988	Water Tube	NB Smith
Elmendorf	42300	01	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1957	Fire Tube Firebox	Birchfield
Elmendorf	42300	02	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1957	Fire Tube	Birchfield
Elmendorf	42300	03	0015	0012	003.40	005.20	DFM	NAG	DFA	S	1957	Fire Tube Firebox	Birchfield
Elmendorf	42400	01	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1957	Fire Tube	Birchfield
Elmendorf	42400	02	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1957	Fire Tube Firebox	Birchfield
Elmendorf	42400	03	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1957	Fire Tube Firebox	Birchfield
Elmendorf	42425	01	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1956	Fire Tube Firebox	Birchfield
Elmendorf	42425	02	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1956	Fire Tube Firebox	Birchfield
Elmendorf	42425	03	0015	0012	004.50	005.20	DFM	NAG	DFA	S	1956	Fire Tube Firebox	Birchfield
Elmendorf	42350	01	0030	0020	569.00	527.00	DFM	NAG	DFA	W	1989	Water Tube	Burnham
Elmendorf	42350	02	0000	0000	002.30	000.00					1967	Dry Back Scotch Marine	
Elmendorf	43410	01	0015	0012	001.00	001.20	DFM	NAG	N/A	S	1956	Fire Tube	Birchfield
Elmendorf	43450	01	0015	0012	008.90	000.00	DFM	NAG	DFA	S	1956	Fire Tube Firebox	Birchfield
Elmendorf	43450	02	0015	0012	008.90	000.00	DFM	DFA	N/A	S	1956	Fire Tube Firebox	Birchfield
Elmendorf	43550	01	0015	0012	004.50	000.00	DFM	NAG	DFA	S	1957	Fire Tube	Birchfield
Elmendorf	43550	02	0015	0012	004.50	000.00	DFM	NAG	DFA	S	1957	Fire Tube Firebox	Birchfield
Elmendorf	43550	03	0015	0012	004.50	000.00	DFM	NAG	DFA	S	1957	Fire Tube Firebox	Birchfield
Elmendorf	52140	01	0125	0015	001.00	000.00	DFM	DFA	N/A	S	1967	Dry Back Scotch Marine	Cleaver Brooks
Elmendorf	62250	01	0015	0012	001.70	000.00	DFM	DFA	N/A	S	1981	Fire Tube Scotch Marine	York Shipley

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	MODEL NO.
Elmendorf	00000	01	-	-	-	-	-
Elmendorf	00000	02	-	-	-	-	-
Elmendorf	00000	03	-	-	-	-	-
Elmendorf	22004	01	-	-	-	-	-
Elmendorf	22004	02	-	-	-	-	-
Elmendorf	22004	03	-	-	-	-	-
Elmendorf	22004	04	-	-	-	-	-
Elmendorf	22004	05	-	-	-	-	-
Elmendorf	22004	06	-	-	-	-	-
Elmendorf	24805	01	-	Gordan Piatt	F16160100U3607	-	-
Elmendorf	24805	02	-	Gordan Piatt	F16160100U3607	-	-
Elmendorf	24805	03	-	Gordan Piatt	F16160100U3607	-	-
Elmendorf	33322	01	SP	Ray Type JP	SN 269222	-	-
Elmendorf	33324	01	SP	Ray Type JP	SN 269222	-	-
Elmendorf	41155	01	-	-	-	-	-
Elmendorf	41755	01	-	Gordan Piatt	NR101-60-20	-	-
Elmendorf	41755	02	-	Gordan Piatt	NR101-60-20	-	-
Elmendorf	41755	03	-	Gordan Piatt	NR101-60-20	-	-
Elmendorf	42300	01	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	42300	02	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	42300	03	-	Iron Fireman	C-240-CO-F	-	-
Elmendorf	42400	01	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	42400	02	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	42400	03	RC	Iron Fireman	Ray RC	-	-
Elmendorf	42425	01	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	42425	02	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	42425	03	-	Iron Fireman	C-240-CO-F	-	-
Elmendorf	42350	01	-	Power Frame	GRI GO-10	-	-
Elmendorf	42350	02	-	-	-	-	-
Elmendorf	43410	01	-	Gordan Piatt	GP-R61-G03	-	-
Elmendorf	43450	01	-	Gordan Piatt	FG14-60-75	-	-
Elmendorf	43450	02	RC	Ray	L890803	-	-
Elmendorf	43550	01	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	43550	02	-	Gordan Piatt	NR101-60-30	-	-
Elmendorf	43550	03	-	Iron Fireman	C-240-CO-F	-	-
Elmendorf	52140	01	RF	Gordan Piatt	R-8-0-05	-	-
Elmendorf	62250	01	RF	York Shipley	FY-208-A2	-	-

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Shemya AFB	00110	01	0015	0014	000.00	000.70	DF2	DF2	N/A	S	1987	Cast Iron	Weil Mclain
Shemya AFB	00110	02	0015	0014	000.00	000.70	DF2	DF2	N/A	S	1987	Cast Iron	Weil Mclain
Shemya AFB	00452	01	0030	0025	000.20	000.17	DF2	DF2	N/A	H	1977	Fire Tube	American Standard
Shemya AFB	00490	01	0030	0025	001.20	002.10	DF2	DF2	N/A	A	1988	Fire Tube	Kewanee
Shemya AFB	00503	01	0150	0050	004.18	003.30		DF2	N/A	S	1987	Fire Tube	Cleaver Brooks
Shemya AFB	00503	02	0150	0050	004.18	003.30		DF2	N/A	S	1987	Fire Tube Scotch Marine	Cleaver Brooks
Shemya AFB	00522	01	0150	0050	005.23	004.20		OIL	N/A	S	1987	Fire Tube	Cleaver Brooks
Shemya AFB	00522	02	0150	0055	005.23	004.20		DF2	N/A	S	1984	Fire Tube	Cleaver Brooks
Shemya AFB	00525	01	0030	0020	000.10	000.15		DF2	N/A	H	1987	Cast Iron	Weil McLain
Shemya AFB	00587	01	0030	0015	001.00	001.00	DF2	DF2	N/A	H	1974	Cast Iron	
Shemya AFB	00600	01	0150	0050	008.64	003.40	DF2	DF2	N/A	S	1987	Fire Tube	Cleaver Brooks
Shemya AFB	00600	02	0150	0045	008.64	003.40	DF2	DF2	N/A	S	1982	Fire Tube	Cleaver Brooks
Shemya AFB	00605	01	0030	0025	000.20	000.18	DF2	DF2	N/A	H	1983	Water Tube	Burnham
Shemya AFB	00613	01	0030	0025	000.80	000.78	DF2	DF2	N/A	H	1967	Fire Tube	Crain
Shemya AFB	00614	01	0030	0025	000.30	000.10	DF2	DF2	N/A	H	1987	Water Tube	Weil McLain
Shemya AFB	00615	01	0030	0025	001.60	000.32	DF2	DF2	N/A	H	1967	Fire Tube	Crain
Shemya AFB	00616	01	0125	0030	001.00	001.00	DF2	DF2	N/A		1971	Water Tube	Bryan
Shemya AFB	00617	01	0030	0025	000.38	000.32	DF2	DF2	N/A	H	1967	Cast Iron	Crane
Shemya AFB	00702	01	0030	0025	005.00	005.20		OIL	DF2	H	1986	Water Tube	Ajax
Shemya AFB	00702	02	0030	0025	005.00	005.20	DF2	DF2	N/A	H	1986	Water Tube	Ajax
Shemya AFB	00727	01	0030	0020	001.00	001.00	DF2	DF2	N/A		1984	Cast Iron	Weil McLain
Shemya AFB	00729	01	0030	0020	000.00	002.00	DF2	DF2	N/A	H	1964	Water Tube	Bryan
Shemya AFB	00731	01	0030	0012	000.30	000.23	DF2	DF2	N/A	H	1987	Cast Iron	Weil McLain
Shemya AFB	03049	01	0625	0200	002.20	000.00					1975	Waste Heat Fire Tube	Vaporphase Corp.
Shemya AFB	03049	02	0625	0200	002.20	000.00					1975	Waste Heat Fire Tube	Vaporphase Corp.
Shemya AFB	03049	03	0625	0200	002.20	000.00					1975	Waste Heat Fire Tube	Vaporphase Corp.
Shemya AFB	03049	04	0625	0060	002.20	000.00					1975	Waste Heat Fire Tube	Vaporphase Corp.
Shemya AFB	03051	11	0160	0060	001.30	000.00					1972	Electric	Cam Industries
Shemya AFB	03051	12	0160	0000	001.30	000.00					1972	Electric	Cam. Industries

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	MODEL NO.
Shemya AFB	00110	01	-	-	-	-	-
Shemya AFB	00110	02	-	-	-	-	-
Shemya AFB	00452	01	-	-	-	-	-
Shemya AFB	00490	01	-	-	-	-	-
Shemya AFB	00503	01	-	-	-	-	-
Shemya AFB	00503	02	-	-	-	-	-
Shemya AFB	00522	01	-	-	-	-	-
Shemya AFB	00522	02	-	-	-	-	-
Shemya AFB	00525	01	-	-	-	-	-
Shemya AFB	00587	01	-	-	-	-	-
Shemya AFB	00600	01	-	-	-	-	-
Shemya AFB	00600	02	-	-	-	-	-
Shemya AFB	00605	01	-	-	-	-	-
Shemya AFB	00613	01	-	-	-	-	-
Shemya AFB	00614	01	-	-	-	-	-
Shemya AFB	00615	01	-	-	-	-	-
Shemya AFB	00616	01	-	-	-	-	-
Shemya AFB	00617	01	-	-	-	-	-
Shemya AFB	00702	01	-	-	-	-	-
Shemya AFB	00702	02	-	-	-	-	-
Shemya AFB	00727	01	-	-	-	-	-
Shemya AFB	00729	01	-	-	-	-	-
Shemya AFB	00731	01	-	-	-	-	-
Shemya AFB	03049	01	-	-	-	-	-
Shemya AFB	03049	02	-	-	-	-	-
Shemya AFB	03049	03	-	-	-	-	-
Shemya AFB	03049	04	-	-	-	-	-
Shemya AFB	03051	11	-	-	-	-	-
Shemya AFB	03051	12	-	-	-	-	-

BASENAME	FACILITY NO.	BOILER NO.	DES PRES	OP PRES	DES CAPACITY	RATED CAPACITY	DES FUEL	PRI FUEL	SEC FUEL	DIST MEDIA	YR BUILT	BOILER TYPE	BOILER MANUFACTURER
Sparrevhon AFS	00002	01	0000	0000	001.40	000.00					0000	Water Tube	
Sparrevhon AFS	00002	02	0000	0000	001.40	000.00					0000	Water Tube	
Sparrevhon AFS	00121	01	0000	0000	001.80	000.00					0000	Fire Tube Firebox	
Sparrevhon AFS	00121	02	0000	0000	003.60	000.00					0000	Fire Tube	
Sparrevhon AFS	00121	03	0000	0000	003.60	000.00					0000	Fire Tube	
Sparrevhon AFS	00250	01	0000	0000	002.10	000.00					0000	Fire Tube Firebox	
Sparrevhon AFS	00250	02	0000	0000	002.10	000.00					0000	Fire Tube	
Sparrevhon AFS	00250	03	0000	0000	000.20	000.00					0000	Cast Iron	
Tatlina AFS	00002	01	0000	0000	002.00	000.00					0000	Water Tube	
Tatlina AFS	00002	02	0000	0000	002.00	000.00					0000	Water Tube	
Tatlina AFS	03055	01	0000	0000	005.20	000.00					0000	Dry Back Scotch Marine	
Tatlina AFS	03055	02	0000	0000	005.20	000.00					0000	Dry Back Scotch Marine	
Tatlina AFS	03055	03	0000	0000	005.20	000.00					0000	Dry Back Scotch Marine	
Tin City AFS	00110	01	0000	0000	004.50	000.00					0000	Fire Tube	
Tin City AFS	00110	02	0000	0000	004.50	000.00					0000	Fire Tube	
Tin City AFS	00110	03	0000	0000	004.50	000.00					0000	Fire Tube	

BASENAME	FACILITY NO.	BOILER NO.	BURNER TYPE	BURNER MANUFACTURER	BURNER MODEL NO.	FUEL PUMP MANUFACTURER	MODEL NO.
Sparrevhon AFS	00002	01	-	-	-	-	-
Sparrevhon AFS	00002	02	-	-	-	-	-
Sparrevhon AFS	00121	01	-	-	-	-	-
Sparrevhon AFS	00121	02	-	-	-	-	-
Sparrevhon AFS	00121	03	-	-	-	-	-
Sparrevhon AFS	00250	01	-	-	-	-	-
Sparrevhon AFS	00250	02	-	-	-	-	-
Sparrevhon AFS	00250	03	-	-	-	-	-
Tatlina AFS	00002	01	-	-	-	-	-
Tatlina AFS	00002	02	-	-	-	-	-
Tatlina AFS	03055	01	-	-	-	-	-
Tatlina AFS	03055	02	-	-	-	-	-
Tatlina AFS	03055	03	-	-	-	-	-
Tin City AFS	00110	01	-	-	-	-	-
Tin City A[illegible]	00110	02	-	-	-	-	-
Tin City AF[illegible]	[illegible]	03	-	-	-	-	-

APPENDIX C

BOILER AND BURNER VENDORS CONTACTED

EQUIP TYPE	COMPANY	ADDRESS	TELEPHONE
Boiler	Babcock & Wilcox Power Generation	P.O. Box 351 Barberton, OH 44203	(800)-354-4400
	Bryan Steam Corp. Dept TR	P.O. Box 27 Peru, IN 46970	(317)-473-6657
	Burnham Corp., Hydronics Div.	P.O. Box 3079-T Lancaster, PA 17604	(717)-293-5846
	Cyclotherm Div. Oswego Package Boiler Co., Inc.	P.O. Box 178 Oswego, NY	-
	Combustion Eng., Inc.	900 Long Ridge Stamford, CT 06902	(203)-329-8771
	Deltak Corp.	P.O. Box 9496T Minneapolis, MN 55440	(612)-544-3371
	Edwards Eng Corp.	101-A Alexander Pompton Plains NJ, 07444	(800)-526-5201
	Kewannee Boiler	Sub COPPUS Engr 101-T Franklin St Kewanee, IL 61443	(309)-853-3541
	Holman Boiler Dept. TR	1956 Singleton Dallas, TX 75212	(214)-637-0020
	Hurst Boiler and Welding Co., Inc	Dept 33 P.O. Box 529 Hwy 319 S. Coolridge, GA 31738	(912)-346-3545
	Ind. Boiler Co.	P.O. Drwer 2258 Thomasville, GA 31799	(800)-476-1314
	Lattner Blr Mfg.	P.O. Box 1527 Cedar Rapids, IA 52406	(800)-345-1527
	Nebraska Blr Co.	P.O. Box 82287 Lincoln, NE 82287	

	Penn Ind. Svcs	P.O. Box 5-T Williamsport, PA 17703-0005	(717)-368-1033
	Showa Teggo	2-8 Muromachi Nihonbashi Chuo-ku Tokyo-To	03-270-5426
	Takuma Co., Ltd	28-12 Ichome Takatanobaba Shinjuku-ku Tokyo-to	03-20-9821
	York-Shipley	693 North Hills Rd York, PA 17402	(717)-755-1081
	Zurn Ind., Inc. Energy Division	1422 East Ave. Erie, PA 16503	(814)-452-6421
Burners	Alpha Blrs, Inc.	2655 Le Jeune Rd, Suite 800 Coral Gables, FL 33134	(305)-442-2233
	Burner & Control Systems, Inc.	641 N. Market St. Chattanooga, TN 37405	(615)-267-9723
	Aki Systems, Inc	14617 F.M. 2920 Tombull, TX 77375	(713)-957-0107
	Aqua-Chem, Inc. Cleaver Brooks	P.O. Box 421 Milwaukee, WI 53201	(414)-962-0100
	C-E Industrial Boiler Ops	1000 Prospect Hill Windsor, CT 06095	(203)-688-1911
	Control Sys. Co.	P.O. Drawer 209 Hudson, OH 44236	(216)-656-3557
	Coppus Engr. Corp.	P.O. Box 15003 Worchester, MA 0615-0003	(508)-756-8393
	Corbett Ind., Inc.	P.O. Box 212 39-T Hewson Ave Waldwick, NJ 07463	(201)-445-6311
	Cowan, Frederick, & Co, Inc.	48-T Kroemer Ave Riverhead NY 11901-3108	(201)-445-6311
	Eastern Engy Svcs	605 Saltaire Way P.O. Box 1019-T Mattituck, NY 11952	(516)-298-3841

Eclipse Combustion	1665 Elmwood Rd Rockford, IL 61103	(815)-877-3031
Flaregas Corp.	100-A Airport Executive Park Spring Valley, NY 10977	(914)-352-8700
Hague Int.	3-T Adams St. South Portland, ME 04106	(207)-799-7346
Macleod & Stewart Co.	157 Rome St, Dept. ICP Farmingdale, NY 11735	(516)-249-1559
Nao, Inc.	L St. & Sedgley Ave Philadelphia, PA 19134	(215)-743-5300
Power Mechanical, Inc	502-T Copeland Dr Hampton, VA 23661	(804)-826-2000
Process Comb. Corp.	Horning & Curry Rd. Pittsburgh, PA 15236	(412)-655-0955
Roberts-Gordon, Inc	1250-T William St Buffalo, NY 14240	(716)-852-4400
T-Thermal	101 Brook Rd Conshohocken, PA 19428	(215)-828-5400
Thermoflux, Inc	6505 S. Lewis, Su 116 Tulsa, OK 74136	(918)-747-9394
Todd Comb., Inc Div of Fuel Tech	61 Taylor Reed Place Stamfort, CT 06906	(203)-359-1320
Woodhill Supply	E 123rd & Euclid Cleveland, OH 44106	(216)-229-3900
WARE, Ivan & Son	4005 Produce Rd Louisville, KY 40218	(800)-228-8861
Zink, John, Co	4401 S. Peoria P.O. Box 702220 Tulsa, OK 74170	(918)-747-1371

APPENDIX D

FUEL ANALYSIS RESULTS: SMALL-SCALE TEST

TABLE D-1. RESULTS OF DIESEL FUEL 2 ANALYSIS

METHOD	TEST	RESULT	MIN	MAX
D4176	APPEARANCE	C&B	C&B	
D4176	WATER & SEDIMENT, VISUAL	NONE	NONE	
D2622	TOTAL SULFUR, WT %	0.20		0.50
D86	DISTILLATION, 50%, DEG C	271		REPORT
D86	DISTILLATION, 90%, DEG C	327		338
D86	DISTILLATION, EBP, DEG C	351		370
D86	DISTILLATION RESIDUE, VOL %	2.0		3
D93	FLASH POINT, DEG C	69	52	
D1298	API GRAVITY	32.7		REPORT
D1298	DENSITY, KG/L @ 15 DEG C	0.862		REPORT
D2500	CLOUD POINT, DEG C	-10		-1
D97	POUR POINT, DEG C	-15		REPORT
D445	VISCOSITY AT 40 DEG C, cST	3.0	1.9	4.4
D3383	HEAT OF COMBUSTION, MJ/KG	47.7		REPORT
D130	COPPER STRIP CORROSION	1A		3
D2276	PARTICULATE MATTER, MG/L	3		10
D524	CARBON RESIDUE, 10% B, % M	0.08		0.35
D976	CETANE INDEX	44	43	

TABLE D-2. RESULTS OF #2 FUEL OIL FUEL ANALYSIS

METHOD	TEST	RESULT	MIN	MAX
D4176	APPEARANCE	HOMOG	HOMOG	
D4176	WATER & SEDIMENT, VISUAL	NONE	NONE	
D2622	TOTAL SULFUR, WT %	0.00		0.50
D86	DISTILLATION 90% DEG C	327	282	338
D93	FLASH POINT, DEG C	77	38	
D1298	API GRAVITY	32.5	30.0	
D1298	DENSITY, KG/L @ 15 DEG C	0.861		0.876
D445	VISCOSITY AT 40 DEG C, cST	3.0	1.9	3.4
D3383	HEAT OF COMBUSTION, MJ/KG	47.8		
D97	POUR POINT, DEG C	-21		-6
D130	COPPER STRIP CORROSION	1A		3
D524	CARBON RESIDUE, 10% B, % M	0.05		0.35
D1796	WATER & SEDIMENT	0.00		0.05

TABLE D-3. RESULTS OF JP-8 FUEL ANALYSIS

METHOD	TEST	RESULT	MIN	MAX
D4176	APPEARANCE	C&B	C&B	
D4176	WATER & SEDIMENT, VISUAL	NONE	NONE	
D156	COLOR, SAYBOLT	+20		REPORT
D3242	TOTAL ACID NUMBER, MG KOH/G	0.004		0.015
D1319	AROMATICS, VOL %	18.0		25.0
D1319	OLEFINS, VOL%	0.5		5.0
D3227	MERCAPTAN SULFUR, WT %	0.000		0.002
D2622	TOTAL SULFUR, WT %	0.00		0.30
D86	DISTILLATION IBP DEG C	173		REPORT
D86	DISTILLATION 10% DEG C	196		205

METHOD	TEST	RESULT	MIN	MAX
D86	DISTILLATION 20% DEG C	202		REPORT
D86	DISTILLATION 50% DEG C	214		REPORT
D86	DISTILLATION 90% DEG C	238		REPORT
D86	DISTILLATION EBP DEG C	264		300
D86	DISTILLATION RESIDUE, VOL %	0.9		1.5
D86	DISTLLATION LOSS, VOL %	0.6		1.5
D93	FLASH POINT, DEG C	60	38	
D1298	API GRAVITY	42.0	37.0	51.0
D1298	DENSITY, KG/L @ 15 DEG C	0.816	0.775	0.840
D2386	FREEZING POINT, DEG C	BELOW -47		-47
D445	VISCOSITY AT -20 DEG C, CST	5.7		8.0
D3383	HEAT OF COMBUSTION, MJ/KG	43.2	42.8	
D3343	HYDROGEN CONTENT, WT %	13.7	13.4	
D1322	SMOKE POINT, MM	25.7	25.0	
D976	CETANE INDEX, CALCULATED	43.0		REPORT
D130	COPPER STRIP CORROSION	1A		1
D3241	THERMAL STABILITY, PD, MM HG	0		25
D3241	THERMAL STABILITY TUBE CODE	2		<3
D3241	THERMAL STABILITY, TDR	2		REPORT
D381	EXISTENT GUM, MG/100 ML	2.0		7.0
D2276	PARTICULATE MATTER, MG/L	0.3		1.0
SPEC	FILTRATION TIME, MIN	10		15
D2624	ELECTRIC CONDUCTIVITY, PS/M	135	150	600
D1094	WATER REACTION, INTERFACE	2		1B
M5342	FSII, VOL %	0.08	0.10	0.15

APPENDIX E

SMALL-SCALE TEST DATA

During the small-scale test runs, data was collected using a PC-based data-acquisition system. For all test runs, data on the heating system temperatures, pressures, flow rates, ambient air dry bulb and wet bulb temperatures, as well as stack oxygen and carbon monoxide were scanned and recorded every five minutes by the data-acquisition system. The heating system was tested for 16 hours each for Oil #2, diesel, and JP-8 to determine boiler baseline performances and for 200 hours to determine the boiler performance for the JP-8 optimized settings. Each of the three baseline and optimized lists of data reported in this appendix is the average of four hours worth of data. ASME Power Test Code 4.1 (14) recommends that when there is inconsistency in the data collected, that inconsistent data should be rejected. Our data selection criteria is based on consistent steam flow rates and temperatures as well as fuel flows. The format of the printed data does not reflect the accuracy of the instrumentation used in these tests.

TABLE E-1. REDUCED DATA FOR #2 FUEL OIL BASELINE TEST

Steam Temperature	=	229.15	F
Condensate Temperature	=	204.41	F
Cooling Water In Temperature	=	71.36	F
Cooling Water Out Temperature	=	137.79	F
Stack Temperature	=	562.31	F
Fuel In Temperature	=	82.91	F
Dry Bulb Temperature	=	112.26	F
Wet Bulb Temperature	=	111.55	F
Steam Pressure	=	5.00	psig
Condensate Pressure	=	20.11	psig
Burner Pump In Pressure	=	.65	psig
Burner Pump Out Pressure	=	150.94	psig
Circ. Pump In Pressure	=	.00	psig
Circ. Pump Out Pressure	=	22.54	psig
Steam Flow	=	50.37	cfm
Fuel Flow	=	.02334	gpm
Air Flow	=	20.65	cfm
O_2 In Flue Gases	=	8.90	%
CO In Flue Gases	=	.00	%
Burner Pump Power	=	239.40	Watts

TABLE E-2. REDUCED DATA FOR DIESEL BASELINE TEST

Steam Temperature	=	229.02	F
Condensate Temperature	=	205.66	F
Cooling Water In Temperature	=	67.81	F
Cooling Water out Temperature	=	142.95	F
Stack Temperature	=	566.23	F
Fuel In Temperature	=	69.97	F
Dry Bulb Temperature	=	69.87	F
Wet Bulb Temperature	=	67.95	F
Steam Pressure	=	4.85	psig
Condensate Pressure	=	7.11	psig
Burner Pump In pressure	=	.00	psig
Burner Pump Out pressure	=	93.02	psig
Circ. Pump In Pressure	=	.00	psig
Circ. Pump Out Pressure	=	.00	psig
Steam Flow	=	47.91	cfm
Fuel Flow	=	.02334	gpm
Air Flow	=	18.99	cfm
O_2 In Flue Gases	=	10.01	%
CO In Flue Gases	=	.00	%
Burner Pump Power	=	241.45	Watts

TABLE E-3. REDUCED DATA FOR JP-8 BASELINE TEST

Steam Temperature	=	231.44	F
Condensate Temperature	=	197.47	F
Cooling Water In Temperature	=	71.01	F
Cooling Water Out Temperature	=	150.04	F
Stack Temperature	=	545.41	F
Fuel In Temperature	=	64.77	F
Dry Bulb Temperature	=	69.87	F
Wet Bulb Temperature	=	67.95	F
Steam Pressure	=	8.12	psig
Condensate Pressure	=	7.82	psig
Burner Pump In Pressure	=	.95	psig
Burner Pump Out Pressure	=	99.38	psig
Circ. Pump In pressure	=	1.33	psig
Circ. Pump Out Pressure	=	1.60	psig
Steam Flow	=	44.53	cfm
Fuel Flow	=	.0226	gpm
Air Flow	=	13.76	cfm
O_2 In Flue Gases	=	10.30	%
CO In Flue Gases	=	.01	%
Burner Pump Power	=	236.21	Watts

TABLE E-4. REDUCED DATA FOR JP-8 PERFORMANCE TEST

Steam Temperature	=	225.24	F
Condensate Temperature	=	211.27	F
Cooling Water In Temperature	=	74.45	F
Cooling Water Out Temperature	=	135.91	F
Stack Temperature	=	567.25	F
Fuel In Temperature	=	87.13	F
Dry Bulb Temperature	=	74.90	F
Wet Bulb Temperature	=	67.62	F
Steam Pressure	=	4.00	psig
Condensate Pressure	=	5.11	psig
Burner Pump In Pressure	=	.32	psig
Burner Pump Out Pressure	=	120.36	psig
Circ. Pump In Pressure	=	.05	psig
Circ. Pump Out Pressure	=	93.62	psig
Steam Flow	=	58.22	cfm
Fuel Flow	=	.02437	gpm
Air Flow	=	20.47	cfm
O_2 In Flue Gases	=	6.32	%
CO In Flue Gases	=	.00	%
Burner Pump Power	=	226.91	Watts

APPENDIX F

DATA ANALYSIS CALCULATION PROCEDURES

A. BOILER DATA ANALYSIS

The American Society of Mechanical Engineers Power Test Code No 4.1 (ASME PTC 4.1) "Steam Generating Units" (14) was adopted on August 8, 1972 and approved for use by the DOD. It recommends two methods for conducting performance tests to determine efficiency, capacity, and other related operating characteristics of steam generating units.

The first method, a direct measurement of the input and output, is called the input-output method. It requires the accurate measurement of the heat inputs to the generating unit, heat absorbed by the feedwater, and the fuel high-heat value. The second method, a direct measurement of heat losses, is called the heat loss method. It requires the determination of the unit heat losses and heat credits as well as the fuel elemental analysis and high-heat value. To establish the capacity at which these losses occur it is necessary to measure either the input or output of the generating unit.

In our testing of the boiler unit at Tyndall AFB, Florida the input-output method was used while both methods were used in testing the boiler unit at McClellan AFB, California. The efficiency calculated using the input-output method herein is referred to as the "Thermal Efficiency." The efficiency calculated using the heat loss method herein is referred to as the "Combustion Efficiency."

The following paragraphs describe the procedures for calculating the thermal and combustion efficiencies.

1. BOILER THERMAL EFFICIENCY

As defined by the ASME PTC 4.1, the input-output method requires the accurate measurement of the quantity and high-heat value of the fuel, heat credits, and heat absorbed by the working fluid. Therefore, the boiler thermal efficiency is expressed as:

$$Thermal\ Efficiency = \frac{Output}{Input} = \frac{Boiler\ Capacity}{Heat\ In\ Fuel + Heat\ Credits} \tag{F-1}$$

The heat credits for both the small-scale and full-scale tests are negligible and assumed zero in the efficiency calculations. The heat in fuel, which is based on the heat of combustion of as-fired fuel, is given by equation (F-2), and the boiler capacity, which is the BTUs per hour absorbed by the feedwater to form steam, is given by equation (F-3).

$$Heat\ In\ Fuel = W_f \times HHV \qquad \textbf{(F-2)}$$

$$Boiler\ Capacity = (W_{stm} \times h_{stm}) - (W_{fw} \times h_{fw}) + (W_{bd} \times h_{bd}) \qquad \textbf{(F-3)}$$

where W_{stm}, W_{fw}, W_{bd}, and W_f are the steam, feedwater, blow-down, and fuel mass flow rates in pounds per hour; h_{stm}, h_{fw}, and h_{bd} are the enthalpies of steam, feedwater, and blow-down in BTUs per pound; and HHV is the high-heat value of fuel per pound of fuel. To calculate the enthalpies mentioned above, steam temperature or pressure for saturated steam or both temperature and pressure for superheated steam, and feedwater temperature are required.

2. BOILER COMBUSTION EFFICIENCY

The combustion efficiency determined by the heat loss method depends on the calculation of the heat losses, heat in fuel, and heat credits. Therefore, the boiler combustion efficiency is expressed as:

$$Combustion\ Efficiency = 1 - \frac{Heat\ Losses}{Heat\ in\ Fuel + Heat\ Credits} \qquad \textbf{(F-4)}$$

The heat losses studied in this investigation are as follows:

a. Heat in dry gas
b. Moisture in fuel
c. Moisture from burning hydrogen
d. Moisture in air
e. Unburned carbon monoxide
f. Radiation and convection

The heat credits term is negligible and assumed zero. The heat in fuel as-fired is the high-heat value per pound of fuel. To calculate the heat losses per pound of fuel, the following measurements are required: stack temperature, oxygen and carbon monoxide in stack dry gases, dry and wet bulb temperatures, as well as the fuel and elemental analysis.

The calculation procedure starts with the fuel combustion equation which is written as:

$$aC + bH_2 + cH_2O + dO_2 + y[eO_2 + fN_2 + gH_2O] \dashrightarrow hCO_2 + iCO + (b+c+g)H_2O + fN_2 + (y-1)[eO_2 + fN_2 + gH_2O] \qquad \text{(F-5)}$$

where the upper case letters are elements and gases in fuel, air, and flue gases. The lower case letters are the pound mole of these elements and gases per pound of fuel. The term $y[eO_2 + fN_2 + gH_2O]$ is the combustion air per pound of fuel while the term $(y-1)[eO_2 + fN_2 + gH_2O]$ represents the excess air.

The fuel elemental analysis gives the fuel elements such as carbon (C%), hydrogen (H_2%), oxygen (O_2%), and water (H_2O%) in weight percent. The pound of moles a, b, c, and d in the combustion equation are calculated as follows:

$$a = \frac{C\%}{12\times 100}, \quad b = \frac{H_2\%}{2\times 100}, \quad c = \frac{H_2O\%}{18\times 100}, \quad d = \frac{O_2\%}{32\times 100} \qquad \text{(F-6)}$$

where 12, 2, 18, and 32 are the molecular weight of carbon, hydrogen, water, and oxygen respectively.

The mole balance for the combustion equation results in the following:

$$a = h + i \qquad \text{(F-7)}$$

$$e = ah + \frac{ai}{2} + \frac{b}{2} - d \qquad \text{(F-8)}$$

and from the air composition of 79% nitrogen and 21% oxygen

$$f = \frac{79}{21} e \qquad \text{(F-9)}$$

From the ORSAT analysis on dry bases, the oxygen, carbon monoxide, carbon dioxide, and nitrogen in flue gases can be derived from the combustion equation into the following expressions:

$$\%O_2 = \frac{(y-1)e}{h + i + f + (y-1)(e+f)} \qquad \textbf{(F-10)}$$

$$\%CO = \frac{i}{h + i + f + (y-1)(e+f)} \qquad \textbf{(F-11)}$$

$$\%CO_2 = \frac{h}{h + i + f + (y-1)(e+f)} \qquad \textbf{(F-12)}$$

$$\%N_2 = 1.0 - (\%O_2 + \%CO_2 + \%CO) \qquad \textbf{(F-13)}$$

where $\%O_2$ and $\%CO$ are the measured volume ratio of oxygen and carbon monoxide in dry flue gases, while $\%CO_2$ and $\%N_2$ are the calculated volume ratio of carbon dioxide and nitrogen in dry flue gases. From equation (F-10) the excess air can be derived as follows:

$$y = \frac{e + \%O_2\,[h+i-e]}{e\,[1-\%O_2\,(e+f)]} \qquad \textbf{(F-14)}$$

Using equations (F-6 through F-13) and the measurements of oxygen and carbon monoxide in the flue gases on dry bases, the excess air 'y', $\%CO_2$, and $\%N_2$ can be calculated from equations (F-12), (F-13), and (F-14).

a. Dry Gas Loss

The dry gas loss in BTUs per pound of as-fired fuel can be calculated from the following equation:

$$Dry\ gas\ loss = 0.24 \times W_{dg} \times (Tstack - Tdb) \qquad \textbf{(F-15)}$$

where 0.24 is the specific heat of the flue gases, W_{dg} is the mass of dry gas per pound of as-fired fuel, Tstack is the stack temperature (in °F), and Tdb is the dry bulb temperature in (°F). The W_{dg} is calculated from the following expression.
where the numerator of the first term represents pounds of dry gas per mole of dry gas and the denominator represents pounds of equivalent carbon burned per mole of dry gas. The C% in the second term is the percent by weight of carbon in as-fired fuel.

$$W_{dg} = \frac{11\ \%CO_2 + 8\ \%O_2 + 7\ (\%N_2 + \%CO)}{3\ (\%CO_2 + \%CO)} \times \frac{C\%}{100} \qquad \textbf{(F-16)}$$

b. Water In Fuel Loss

The water in fuel loss is due to the loss of the heat consumed to evaporate and raise the temperature of the fuel water content from ambient condition to stack condition. It is calculated from the following expression:

$$Water\ In\ Fuel\ Loss = \left(\frac{H_2O\%}{100}\right)[1089.00 + (0.46 \times Tstack) - (1.0 \times Tdb)]$$

(F-17)

where $H_2O\%$ is the weight percent of water in as-fired fuel. The term [1089.00 + (0.46xTstack)] is the enthalpy of the water vapor at stack temperature (Tstack in °F) and vapor partial pressure of one psia. The term [1.0 x Tdb] is the enthalpy of saturated liquid at the temperature Tdb (in °F).

c. Hydrogen In Fuel Loss

Hydrogen in fuel burns into water vapor during combustion. The hydrogen in fuel loss is due to the loss of the heat in that water vapor at stack condition. It is calculated from the following expression:

$$Hydrogen\ In\ Fuel\ Loss = 8.936\left(\frac{H_2\%}{100}\right) \times [1089.00 + (0.46 \times Tstack) - (1.0 \times Tdb)] \qquad \textbf{(F-18)}$$

where 8.936 is the pounds of water produced from burning one pound of hydrogen, and $H_2\%$ is the weight percent of hydrogen exclusive of that in fuel moisture per one pound of as-fired fuel. The term [1089.0 + (0.46xTstack) - (1.0xTdb)] is defined in paragraph 2.2.

d. Moisture In Air Loss

The moisture in combustion air loss is due to the energy spent to heat it from ambient temperature to stack temperature. This loss can be calculated from stack and dry bulb temperatures and the pound moisture in combustion air per pound of as-fired fuel. The steps involved are:

(1) The humidity ratio (HR) of combustion air is calculated from the dry and wet bulb temperatures by conducting a heat balance. The humidity ratio of air is given in the form:

$$HR = \frac{Cp(Twb - Tdb) + HRsat\ (hg(Twb) - hf(Twb))}{(hg(Tbd) - hf(Twb))} \qquad \textbf{(F-19)}$$

where Cp is the specific heat of air, Twb is the wet bulb temperature, Tdb is the dry bulb temperature, hg(T) is the saturated steam enthalpy calculated at temperature T, hf(T) is the saturated water enthalpy calculated at temperature T, and HRsat is the humidity ratio of saturated air at Twb. HRsat, which is the humidity ratio calculated at saturation conditions, is given in the form:

$$HRsat = 0.622\ \frac{Psat}{14.696 - Psat} \qquad \textbf{(F-20)}$$

where Psat is the saturated pressure at Twb.

(2) The amount of moisture in combustion air in pounds per pound of as-fired fuel (W_{HR}) can be calculated using equations F-5, F-8, F-9, F-14, and F-19 as follows:

$$W_{HR} = HR\ (28.9)\ (e+f)\ y \qquad \textbf{(F-21)}$$

(3) Hence, the moisture in air loss is calculated from the following equation:

$$Moisture\ In\ Air\ Losses = 0.46\ W_{HR}\ (Tstack - Tdb) \qquad \textbf{(F-22)}$$

where 0.46 is the specific heat of water vapor.

e. Carbon Monoxide Loss

Incomplete combustion of carbon produces carbon monoxide. The unburned carbon monoxide loss is equal to the heat of combustion of carbon monoxide times the amount of unburned carbon monoxide per pound of as-fired fuel. This is calculated from the following expression:

$$Carbon\ Monoxide\ Loss = 10160 \times \frac{\%CO}{(\%CO_2 + \%CO)} \times \frac{C\%}{100} \qquad \textbf{(F-23)}$$

where 10160 is the BTUs generated from burning one pound of CO to CO_2, %CO and %CO_2 are volume ratios of carbon monoxide and carbon dioxide in dry flue gases, and C% is the carbon percent by weight in as-fired fuel.

f. Radiation and Convection Losses

The radiation and convection losses are due to the difference in the boiler outer surface and ambient air temperatures. These losses usually account for two to three percent of the boiler efficiency. In our efficiency calculations we did not include the radiation and convection losses.

The addition of all losses mentioned in 2.a through 2.f gives the total heat losses per pound of as-fired fuel. This total is used in equation (F-4) along with the high-heat value of as-fired fuel to calculate the boiler combustion efficiency.

In the efficiency calculations conducted for the full-scale test the economizer outlet temperatures of the feedwater and flue gases were used. Thus the economizer was treated as an integral part of the boiler.

B. SMALL-SCALE JP-8 FLOW ADJUSTMENT

The JP-8 optimized runs were conducted at increased fuel flow rate to achieve the same boiler capacity as that of the Oil #2 runs. To calculate the optimized JP-8 flow rate the thermal efficiency equation (equation F-1) is rewritten in a different form using equation (F-2) as:

$$W_f = \frac{Boiler\ Capacity}{Thermal\ Efficiency\ x\ HHV} \qquad \textbf{(F-24)}$$

Using the JP-8 baseline boiler efficiency of 81.6% and the Oil #2 boiler capacity of 151,000 BTU/hr, the JP-8 flow rate calculated from equation (F-24) is 1.46 gal/hr. To obtain this flow rate at the burner nozzle the fuel pump discharge pressure was increased from the 100 psig level set for Oil #2 operation until the fuel flow sensor output indicated a JP-8 flow of 1.46 gal/hr. At that flow rate the measured pump discharge pressure was 120 psig.

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APPENDIX G

SMALL-SCALE TEST DATA ANALYSIS AND RESULTS

The boiler efficiencies reported in this appendix are based on the input-output method. This method is detailed in Appendix F. The steam and water properties were calculated from the steam and condensate temperatures using a proprietary computerized library, based on ASME STEAM TABLES, Fifth Edition 1983 (15).

A summary of the boiler thermal efficiency calculation results follows. The format of the printed data does not reflect the accuracy of instrumentation used in these tests.

TABLE G-1. #2 FUEL OIL BASELINE TEST DATA ANALYSIS AND RESULTS

Steam Enthalpy	=	1156.75	BTU/lb
Steam Specific Volume	=	19.67	cu ft/lb
Condensate Enthalpy	=	172.52	BTU/lb
Boiler Capacity	=	151245.69	BTU/hr
Fuel High-Heat Value	=	140300.00	BTU.gal
Heat Input from Fuel	=	196448.58	BTU/hr
BOILER THERMAL EFFICIENCY	=	76.99	%

TABLE G-2. DIESEL BASELINE TEST DATA ANALYSIS AND RESULTS

Steam Enthalpy	=	1156.70	BTU/lb
Steam Specific Volume	=	19.71	cu ft/lb
Condensate Enthalpy	=	117.38	BTU/lb
Boiler Capacity	=	143333.77	BTU/hr
Fuel High-Heat Value	=	140180.00	BTU.gal
Heat Input from Fuel	=	196330.65	BTU/hr
BOILER THERMAL EFFICIENCY	=	73.01	%

TABLE G-3. JP-8 BASELINE TEST DATA ANALYSIS AND RESULTS

Steam Enthalpy	=	1157.57	BTU/lb
Steam Specific Volume	=	18.90	cu ft/lb
Condensate Enthalpy	=	165.54	BTU/lb
Boiler Capacity	=	140236.82	BTU/hr
Fuel High-Heat Value	=	126466.00	BTU.gal
Heat Input from Fuel	=	171903.39	BTU/hr

BOILER THERMAL EFFICIENCY	=	81.58	%

TABLE G-4. JP-8 PERFORMANCE TEST DATA ANALYSIS AND RESULTS

Steam Enthalpy	=	1155.34	BTU/lb
Steam Specific Volume	=	21.07	cu ft/lb
Condensate Enthalpy	=	179.43	BTU/lb
Boiler Capacity	=	161785.44	BTU/hr
Fuel High-Heat Value	=	126466.00	BTU.gal
Heat Input from Fuel	=	184946.12	BTU/hr
BOILER THERMAL EFFICIENCY	=	87.48	%

APPENDIX H

SMALL-SCALE TEST EMISSIONS SAMPLING, ANALYSIS, AND RESULTS

The sub-scale boiler's emissions were sampled and analyzed for particulates, nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and organic compounds. Sampling was conducted during operational trials with heating oil, diesel fuel, and JP-8. Trials with heating oil and diesel fuel were conducted for two days each, and trials with JP-8 were conducted for about two weeks, but optimized conditions for operating with JP-8 were not established until late in the sampling period. When optimized JP-8 conditions were established, the boiler was operated with these conditions for two days to permit the emissions sampling to be performed.

Several of the measurements were made using measurement methods based on techniques accepted by the California Air Resources Board (CARB). Of the CARB techniques used, Methods 4, 5, and 7 were identical in their CARB forms to the same-numbered methods from the U.S. Environmental Protection Agency (EPA). Method 6 differed in the CARB form in that the CARB description lists only a midget impinger procedure while the EPA allows either midget of full-sized impingers to be used.

A. SAMPLE COLLECTION

1. NO_2 Collection and Analysis

The NO_2 measurements were conducted using the California Air Resources Board Method 7 (16). This method collects a grab sample of the stack gas in an evacuated flask, using apparatus as shown in Figure H-1. The sampling glassware was composed of borosilicate glass. The probe, control stopcock, gauge tee, and pump valve were connected with 5/12 spherical glass joints. Pressure in the probe and sampling apparatus was measured with a high precision digital absolute pressure gauge (Pennwalt Corp., Wallace & Tiernan Division) connected with metal tubing to the sampling glassware. A mechanical oil rough pump (Edwards High Vacuum, model E2M2) was used to evacuate the apparatus. This apparatus differed from the standard apparatus described in US EPA and CARB Methods 7 by the substitution of the absolute pressure gauge for the mercury manometer used in the standard methods.

The NO_2 absorbing solution was prepared by adding 2.8 mL of concentrated sulfuric acid (H_2SO_4) to 1 liter of distilled, deionized water, and pipetting 600 µL of 30 % hydrogen peroxide (H_2O_2) into the solution. This solution was prepared fresh before each sampling. Phenoldisulfonic acid solution for the sample analysis procedure was prepared by dissolving 25 grams of phenol in 150 mL of concentrated H_2SO_4 with the aid of a hot plate. The solution was then cooled, 75 mL of concentrated H_2SO_4 was added, and the solution was heated on the hot plate at 100°C for two hours.

The resulting solution was stored in a dark-tinted bottle with a glass stopper.

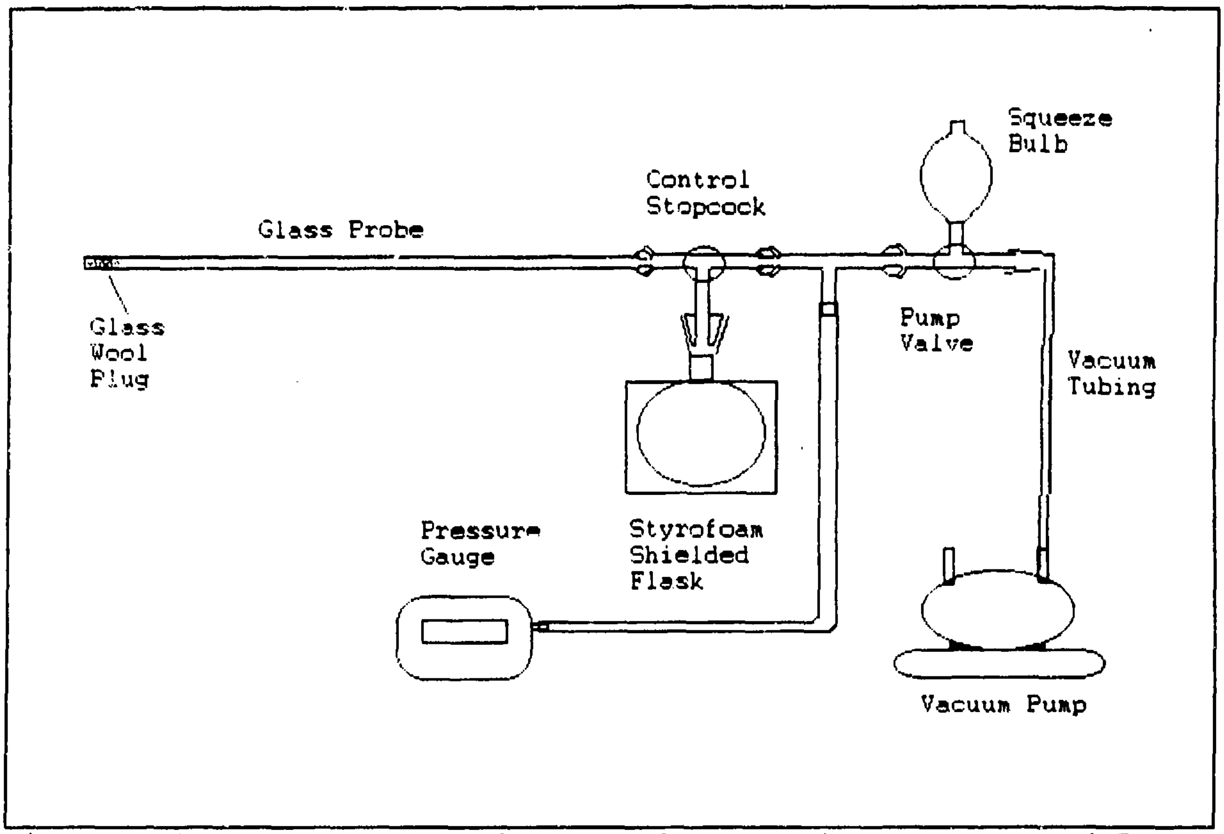

Figure H-1. Apparatus used to sample NO_2 using CARB Method 7.

Prior to collecting the sample, the sampling flask was charged with 25 mL of freshly prepared absorbing solution and was assembled with the rest of the sampling apparatus, using vacuum grease to prevent leaks. Immediately prior to sampling, the flask was evacuated to a pressure of 75 torr or less, and leak checks were performed by sealing the flask and monitoring the interior pressure. When the leak check was satisfactory, the stack gas was admitted to the flask with the controlling stopcock. The temperature and absolute pressures of the apparatus were taken immediately prior to and at the end of the sampling. The pressure of the stack was also measured. Following the sample collection, the flask was sealed with the stopcock and the sample was transported back to the analytical laboratory. The sample was allowed to sit for approximately four to five days to ensure complete absorption of the NO_2. The stack gas was assumed to contain sufficient oxygen to convert all NO_x species to NO_2.

After the sample had been allowed to sit for the required length of time, the sample flask was re-connected with the pressure gauge, and the pressure and temperature in the flask were recorded.

The solution inside the flask was then decanted into a 100 mL beaker. The flask was rinsed with two 5 mL aliquots of distilled deionized water, and the rinsings were added to the 100 mL beaker with the rest of the flask's contents. The recovered solution was then made basic, to a pH of between 9 and 12 with 1 N sodium hydroxide (NaOH). The contents of the beaker were then transferred with distilled water rinsings to a 50 mL volumetric flask. The contents were then diluted to the volume of the 50 mL flask with distilled deionized water.

The contents of the 50 mL volumetric flask were then transferred quantitatively to a 250 mL beaker and then evaporated to dryness over a hot plate. The dried material was then re-dissolved and reacted with 2 mL of phenoldisulfonic acid solution. Following the phenoldisulfonic acid treatment, 1 mL of distilled deionized water and four drops of concentrated H_2SO_4 were added, and then the solution was heated on the hot plate for 3 minutes with occasional stirring. The solution was cooled and then diluted with 20 mL of distilled deionized water, and the solution was brought to a pH of 10 with concentrated ammonium hydroxide (NH_4OH). The resulting solution usually contained some solids and had to be filtered, using a coarse filter paper (Whatman No. 41). The filtrate was collected in a 100 mL volumetric flask and diluted to the mark with distilled deionized water.

The measurement was standardized by a series of potassium nitrate (KNO_3) standard solutions, produced from a standard solution with a concentration of 2.198 g/L. Aliquots were pipetted into 50 mL volumetric flasks, along with 25 mL of absorbing solution. The pH of the standards was adjusted to between 9 and 12 with 1 N NaOH, and the solutions were made up to the volumes of the 50 mL volumetric flasks. The solutions were then quantitatively transferred to 250 mL beakers and carried through the evaporation and phenoldisulfonic acid procedure used for the unknowns. The standards were transferred to 100 mL volumetric flasks.

Portions from the prepared unknowns and standards were transferred to quartz spectrophotometer cells and the absorbances of the solutions at 410 nm were read with a single beam spectrophotometer (Model DU-65, Beckman, Inc). The absorbances and concentrations of the standards were used to generate a standard curve, from which the concentration of NO_2 in the unknown was obtained.

2. SO_2 Collection and Analysis

The SO_2 measurements were conducted using the CARB Method 6 (16). In this method, the stack gases are pumped via a heated glass probe through a train of midget impingers loaded with absorbing solutions, where the SO_2 is absorbed and converted to the sulfate (SO_4^{--}) species. The apparatus, illustrated in Figure 2, was assembled from borosilicate glassware with 5/12 spherical glass joints. Midget impingers, of 30 mL capacities, were used for all four impingers in the train. A borosilicate glass probe, of 6 mm inner diameter, with a 5/12 spherical inner glass joint, and with a silanized glass-wool plug in the tip was used to obtain stack gases. A diaphragm type pump (Model 4Z024, Dayton Electric Mfg. Co.) was used to draw the stack gases through the impinger train and drying tube. A gas meter measured the volume of the sampled gases, and was equipped with a pressure gauge and thermometer to monitor the gas meter's internal temperature and pressure.

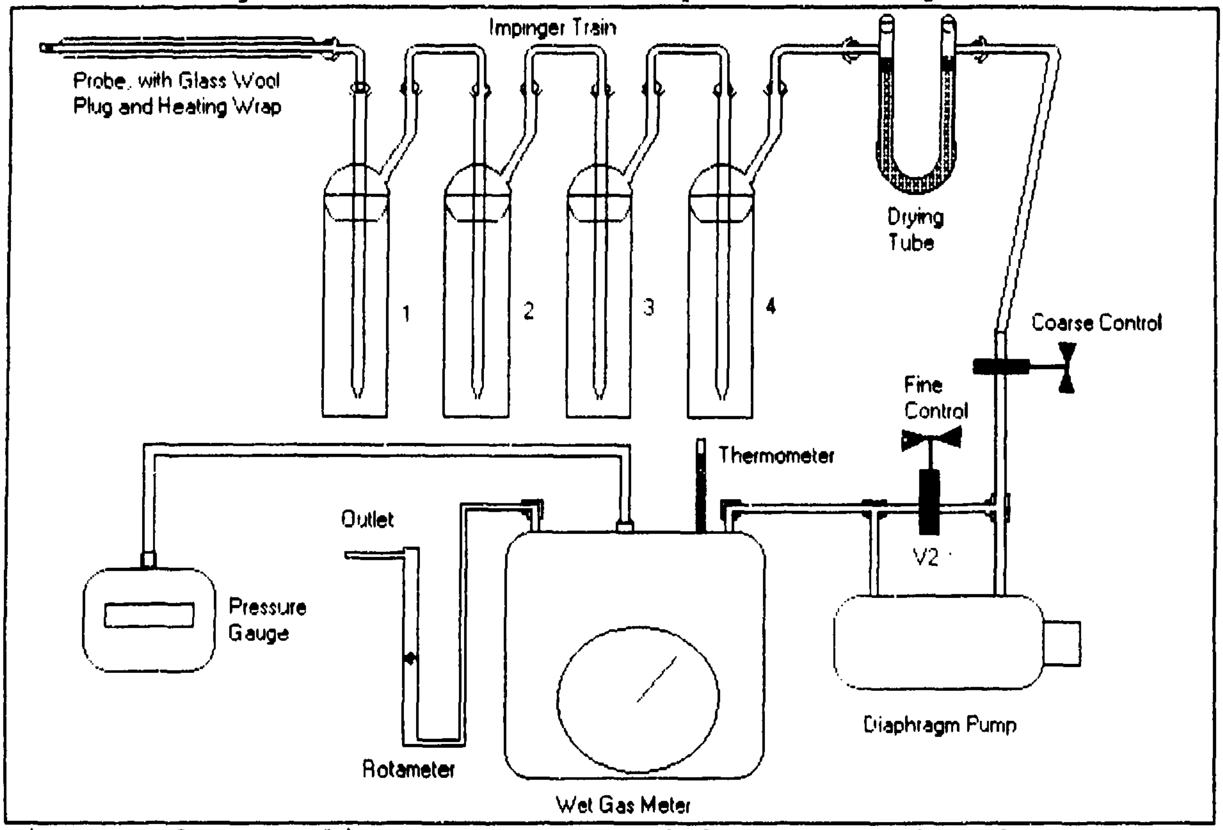

Figure H-2. Sampling apparatus used for CARB Method 6 SO_2 Collection.

To prepare for sample collection, the first impinger (Impinger 1 in the Figure H-2) was charged with 15 mL of 80 percent isopropanol in water. The second and third impinger were each charged with 15 mL of freshly prepared 3 percent H_2O_2. The final impinger was left dry. The drying tube was filled with 60-80 mesh silica gel to slightly below the level of the glass plugs, and the silica gel was packed in with silanized glass wool. The probe was wrapped with heating tape and a small plug of silanized glass wool was placed in the tip. The impinger train was set up in an ice bath, and all glassware connections were then made.

Each sample was collected by drawing stack gases through the impinger train with a constant flow rate of approximately 1.0 L/min for 20 minutes, followed by purging the apparatus by drawing ambient air at the same flow rate for the same amount of time. Following the collection, the glassware connections were opened and the impinger contents were transferred quantitatively and combined into a polyethylene bottle. The bottle was closed, labelled, and transported to the laboratory for analysis.

The samples were transferred quantitatively to 100 mL volumetric flasks and diluted to the mark with distilled deionized water. Small aliquots (5 mL) were pipetted from the volumetric flask into a 50 mL beaker, 20 mL of 100 percent isopropanol were added, and four drops of thorin indicator were added. The sample was then titrated with standardized 0.01 N barium chloride ($BaCl_2$). The titration was carried to a faint pink end-point. The end-points were difficult to see with certainty, and so the sample was titrated in comparison with an un-titrated sample and a sample which had already reached its end-point. A slow titration technique was used as the end-point was sometimes slow to develop. Due to the difficulties in accurately reading the thorin end-point, multiple trials were made, un-reliable readings discarded, and the remaining readings were averaged. SO_2 in the sample was calculated from the concentration of SO_4^{--} in the titrated samples.

Prior to the titration of the unknown samples, a 0.01N NaOH standard solution was prepared and standardized by titrating dried primary standard potassium hydrogen phthalate (KHP). The 0.01 N NaOH solution was then used to standardize a 0.01N solution of H_2SO_4. These acid-base titrations were made using phenolphthalein as an indicator. The standardized H_2SO_4 was used to standardize a 0.01 N solution of $BaCl_2$ using thorin indicator. As described in the procedure for the unknown, above, the thorin titration was carried to a faint pink end-point, and before-and-after color references were used to accurately determine the color change. Multiple standardization trials were required due to the uncertainty of the thorin end-point.

The titrations gave the number of moles of SO_4^{--} in each sample, which was also the number of moles of SO_2 collected in each sample. The weight of SO_2 in each sample was then the number of moles multiplied by the formula weight. The volume of dry air sampled was read by the gas meter and corrected to standard conditions of 25°C and 760 torr.

3. Particulate Collection and Analysis

The particulate emissions and water vapor emissions from the sub-scale boiler were measured by a modification of the CARB Methods 4 and 5. The Method 4 procedures were used to estimate the amount of water vapor in the stack gases, and the Method 5 procedures were used to measure the particulates. Both methods were performed at the same time with the same apparatus, as the Method 4 procedures were incorporated into Method 5. Some modifications had to be made to conform to the physical characteristics of the sub-scale boiler.

Particulates from the stack gas were collected on a glass fiber filter, and were quantitated by weighing the dried filter before and after the collection. The sampling apparatus is illustrated in Figure H-3. All glassware was made of borosilicate

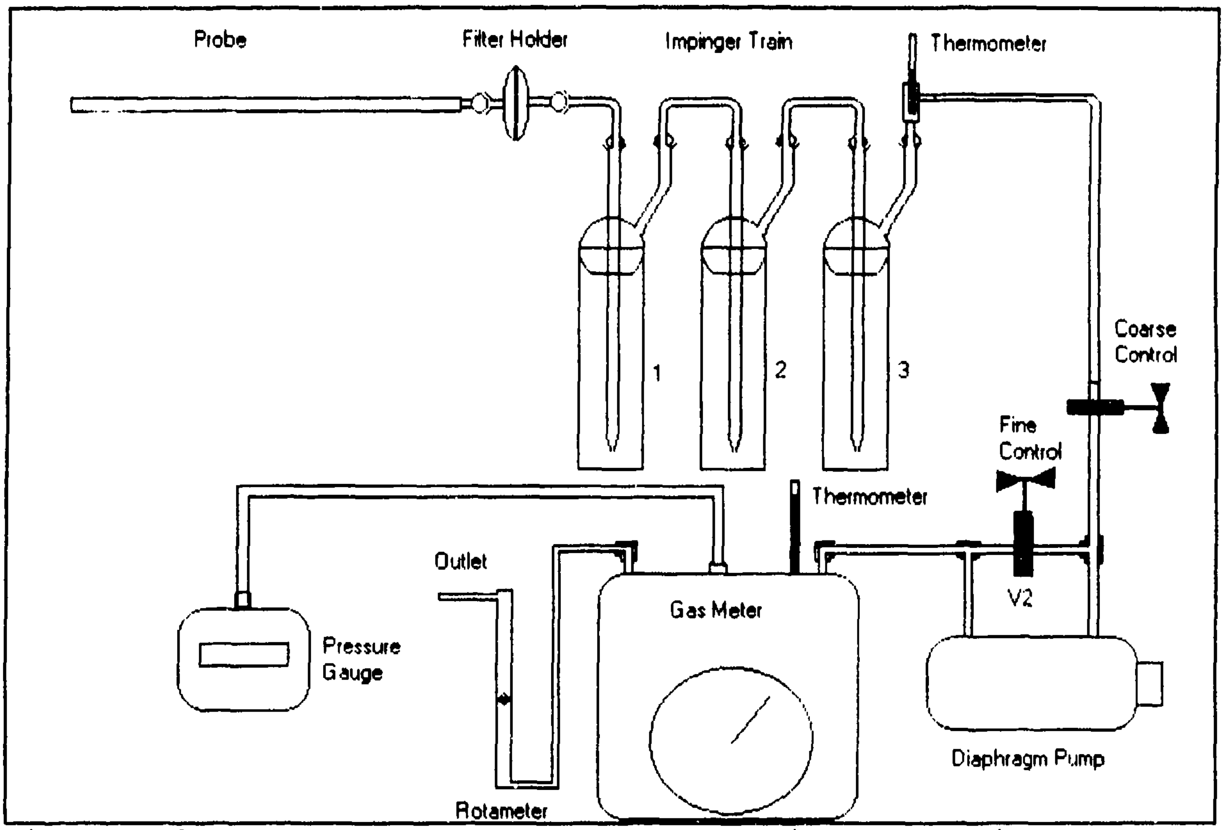

Figure H-3. Apparatus used to sample particulates using CARB Method 5.

glass. Full-sized impingers were used, and the glassware was joined with 28/15 spherical glass joints. A Diaphragm type pump (Model 4Z024, Dayton Electric Mfg. Co.) was used to draw the stack gases through the apparatus. Each sample was collected on a single sheet of glass fiber filter medium (Whatman, type GF/C) held in a glass filter holder with a glass frit filter support. Sample traverses of the stack were not performed because of the small-diameter stack. All samples were collected with the probe tip placed at the center of the stack. The sampling was not conducted isokinetically. The pitot tube used for a proper Method 5 isokinetic collection was not used. Also, no probe nozzle was available to fit the glass tubing of the probe, so the orifice orientation differed from that presrcibed in the CARB Method. The probe tubing and the filter holder were wrapped with electrical heating tape during sample collection, and the heating tape temperature was maintained high enough to prevent condensation in the probe or filter holder. The restricted local supply of impingers forced the assembly of the impinger train with only three impingers. Normally, Method 5 trains are prepared by charging the first two impingers (upstream) with distilled, deionized water, leaving the third impinger empty, and charging the fourth and final impinger with silica gel. The loss of the empty impinger probably did not result in the loss of any of the moisture catch, since the silica gel was adequate to trap any moisture leaving the second impinger. Thus the use of three impingers was judged to be sufficient.

Prior to collecting the particulate sample, the filter sheet was oven dried overnight at 120°C and then cooled to room temperature for 30 minutes prior to being weighed to the nearest 0.01 mg. The filter sheet was then assembled into a labelled glass filter holder assembly.

To collect a sample, the first two impingers were filled with 100 mL distilled deionized water, and weighed to the nearest 0.1 gram. The third (final) impinger was filled with 200 grams of 60-80 mesh silica gel and weighed to the nearest 0.1 gram. The filter holder assembly, with the filter, was also weighed to the nearest 0.1 gram. The coarse weighings (to 0.1 gram) were used to measure the amount of water condensate which was collected in each of the impingers and the filter holder assembly. The impinger train was assembled, and all impinger train connections were made. All glassware joints were sealed with vacuum grease (Dow Corning, Inc.) and the spherical joints were clamped. When the impinger train connections were secure, the ice bath was filled with crushed ice. The probe was adjusted to place the opening in the center of the stack, and the filter holder was then installed and connected to the stack and the impinger train. The probe and filter holder were then wrapped with heating tape and heated. When the sample collection train was ready, the pumping system was switched on and stack gases were drawn through the system for approximately one hour.

When the sampling was completed, the pump and probe heater were switched off. The impingers were removed from the impinger train, wiped free of external moisture, and weighed to the nearest 0.1 gram. The filter holder was allowed to cool to ambient temperature and was then weighed to the nearest 0.1 gram. The filter holder was then transferred to the laboratory. The filter was removed from the holder, while using care to avoid tearing material from the filter. After removal, the filter was placed in a petri dish and heated in a drying oven at 120°C overnight. The filter was cooled for 30 minutes in a desiccator and weighed to the nearest 0.01 mg. The amount of particulates in the stack gas was indicated by the weight gain of the filter, and the moisture in the stack gas was indicated by the weight gain by the filter holder assembly and the impingers.

4. Organic Emissions Collection and Analysis

The organic emissions from the sub-scale boiler were collected by sorbing onto small activated charcoal traps from stack gases pumped through the traps. The apparatus used is diagrammed in Figure H-4. The traps contained 5 mg of activated charcoal each and were assembled into thick-walled 6 mm O.D. chromatography tubing. The traps were available commercially as accessories to closed loop stripping systems (Tekmar, Inc.). The stack gases were drawn through a stainless steel probe into the traps, using a diaphragm pump, and the sample volume was measured with a wet gas meter. The temperature and pressure of the gas flowing through the wet gas meter were determined with a high precision, digital, absolute pressure gauge and a thermometer. The stack gases were permitted to cool to near ambient temperature prior to their reaching the trap tubes, so that sorbtion would be maximized. Following sample collection, the trap tubes were transported to the laboratory, and the trapped organics were extracted with a micro-extraction procedure using a 50 µL aliquot of dichloromethane (CH_2Cl_2). The extract was collected in a 100 µL autosampler vial, with a teflon-faced silicone septum and a screw-cap lid. The extract was analyzed by gas chromatography, using a fused silica capillary column and a flame-ionization detector. Samples of the extract could also be injected into a gas chromatograph/mass spectrometer, to obtain mass spectra of the components which could, in-turn, permit the organic species in the samples to be identified.

In a few preliminary trials, two charcoal traps were used in series, so that any organics which broke through the first trap would be indicated on the second. The use of the second trap resulted in greatly reduced flow rates through the traps, which reduced the sample sizes and raised the limits of detection for the method. Initial trial samplings indicated that the concentration of organics in the stack gas was normally low and that there was little danger of breakthrough, so the use of the second trap was discontinued. Also, the deletion of the second trap was desirable because an important goal in sampling from the sub-scale boiler was to identify what types of organic compounds were present in the stack gases so that quantitative standards could be selected and prepared, and this demanded that samples of the organic compounds be as concentrated as possible, which, in turn, called for collecting larger sample sizes.

The extracts were analyzed by gas chromatography using a fused silica capillary column coated with a nonpolar stationary phase (DB-5, J&W Scientific, Inc.). The chromatographic conditions used are summarized in Table H-1. The organic components were detected with a flame ionization detector, interfaced through an analog-to-

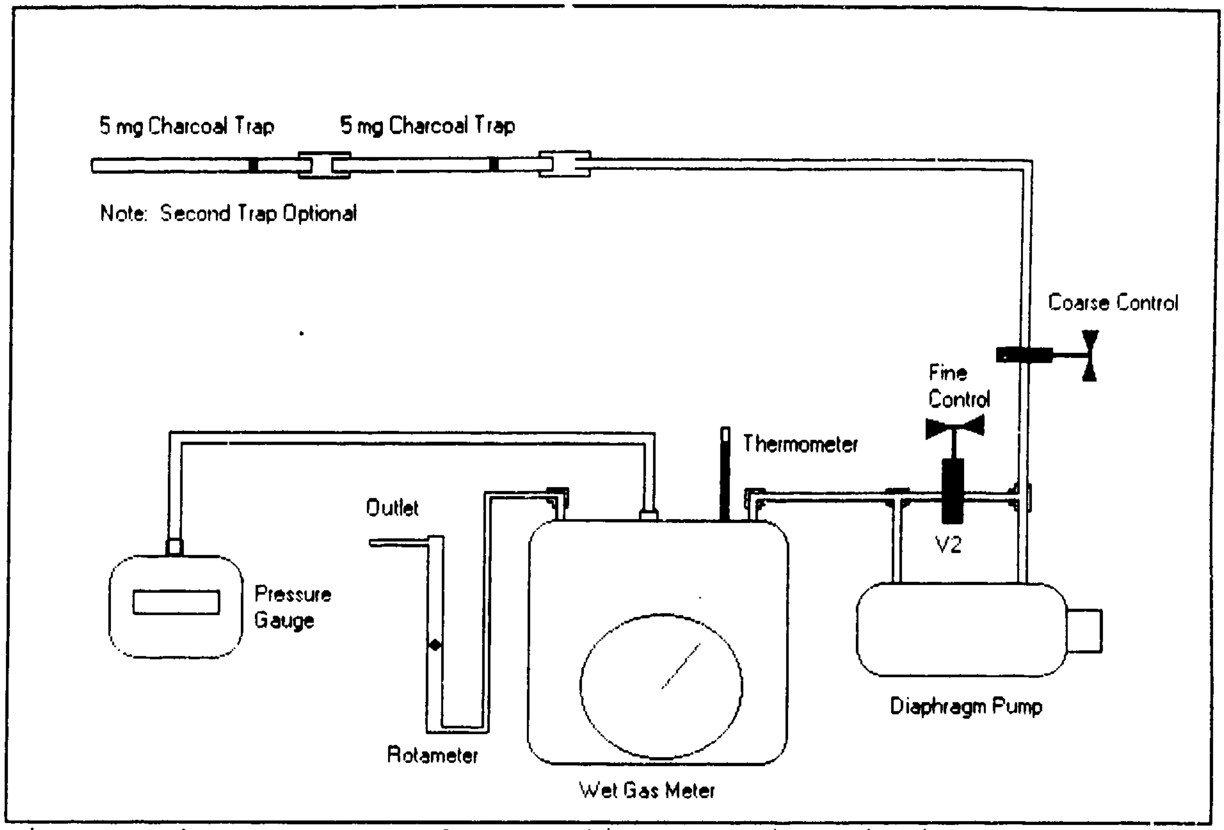

Figure H-4. Apparatus for sampling organic emissions from the sub-scale boiler.

digital convertor into a laboratory automation system (HP-3357, Hewlett-Packard Co.). The chromatograms were aquired and stored digitally.

TABLE H-1. GAS CHROMATOGRAPHIC CONDITIONS

Column Type:	Fused Silica Capillary
Column Stationary Phase:	HP-5
Column Stationary Phase Thickness:	0.3[illegible] µm
Column Length:	10 m
Column Inner Diameter:	0.10 mm
Detector Type:	Flame Ionization Detector
Initial Temperature:	40 °C
Initial Isothermal Hold Time:	2 min
Temperature Programming Rate:	12 °C/min
Final Temperature:	250 °C
Final Isothermal Hold Time	10 min
Injector Temperature:	250 °C
Detector Temperature:	270 °C
Injection Port Purge Start Time:	0.34 min
Injection Port Purge Stop Time:	29 min

B. RESULTS

The results of the SO_2 analyses by CARB Method 6 are listed in Table H-2. The SO_2 concentrations are given in terms of milligrams per cubic meter and in terms of parts per million by weight of dry air. Results of the NO_2 analyses by CARB Method 7 are listed in Table H-3. The NO_2 concentrations are given in terms of milligrams per cubic meter and in terms of parts per million by weight of dry air. Results of the particulate analyses by CARB Method 5 and the moisture analyses by CARB Method 4 are listed in Table H-4 and Table H-5, respectively. The particulate results are given in terms of milligrams per cubic meter and in terms of parts per million by weight of dry air. The moisture results are given in terms of grams per cubic meter and in terms of weight percent in dry air.

TABLE H-2. SO_2 CONCENTRATION RESULTS BY CARB METHOD 6

Fuel Type	Conc. (mg/m^3)	Conc. (ppm)
Diesel	59.0 mg/m^3	50 ppm
No. 2 Fuel Oil	106 mg/m^3	90 ppm
JP-8 Fuel (Baseline)	31.3 mg/m^3	26 ppm
JP-8 Fuel (Performance)	14.8 mg/m^3	13 ppm

TABLE H-3. NO_2 CONCENTRATION RESULTS BY CARB METHOD 7

Fuel Type	Conc. (mg/m^3)	Conc. (ppm)
Diesel trial 1	133 mg/m^3	112 ppm
Diesel trial 2	85.2 mg/m^3	72 ppm
No. 2 Fuel Oil trial 1	146 mg/m^3	123 ppm
No. 2 Fuel Oil trial 2	112 mg/m^3	94 ppm
JP-8 Fuel (Baseline) 1	144 mg/m^3	121 ppm
JP-8 Fuel (Baseline) 2	104 mg/m^3	88 ppm
JP-8 Fuel (Performance)	81.4 mg/m^3	69 ppm

TABLE H-4. PARTICULATE COUNTS BY CARB METHOD 5

Fuel Type	Conc. (mg/m^3)	Conc. (ppm)
Diesel	6.45 mg/m^3	5 ppm
No. 2 Fuel Oil	2.44 mg/m^3	2 ppm
JP-8 Fuel (Baseline)	1.94 mg/m^3	2 ppm
JP-8 Fuel (Performance)	29.9 mg/m^3	25 ppm

TABLE H-5. MOISTURE AMOUNTS BY CARB METHOD 4

Fuel Type	Conc. (g/m^3)	Conc. (%)
Diesel	50.2 g/m^3	4.24 % (w/w)
No. 2 Fuel Oil	59.2 g/m^3	4.99 % (w/w)
JP-8 Fuel (Baseline)	62.9 g/m^3	5.31 % (w/w)
JP-8 Fuel (Performance)	62.4 g/m^3	5.26 % (w/w)

The original strategy for processing the organic results was to attempt to identify some of the major products, and then prepare standards to permit their quantitation. The actual organic sampling results varied greatly, with some samples bearing high oranic loads and producing profiles which resembled the original fuel material used in the boiler during that sampling, and with other organic samples showing very small sample catches. It proved impractical to identify the components from the samples with small catches, because the peaks encountered were present in too small quantities to permit useable mass spectra to be obtained. The samples obtained were either present at such low levels as to preclude obtaining mass spectra which were complete enough to identify, or they were very high but the profiles were clearly those of unburned fuel. Eventually, it was noticed that the samples showing high concentrations of organics, and which exhibited profiles resembling those of fuels were obtained from runs where the boiler flame extinguished during the sampling period. Samples collected during runs where the boiler was not extinguish showed very low levels of organics, and none of their components could be identified.

C. CONCLUSIONS

JP-8 Fuel appears to compare favorably with Diesel and No. 2 Fuel Oil in terms of its SO_2 emissions. The situation in terms of the NO_2 and particulate emissions is less clear cut. Fairly wide discrepancies were obtained from the NO_2 measurements, and the performance JP-8 value of 81.4 mg/m^3 may be an artifact, since the duplicate sample for that trial was destroyed in transit to the laboratory. Maximum concentrations of NO_2 were similar for operations with Diesel, No. 2 Fuel Oil, and JP-8 operated under baseline conditions. There were a number of experimental difficulties associated with the particulate collection, so that it is unwise to draw any conclusions from the particulate data collected from the sub-scale boiler.

The organic emission sampling showed that the largest organic emissions occured when the flame was extinguished or re-ignited. When these events occured during sampling, the fuel vapor overwhelmed all other organic emissions which were collected during the sample period. No other information was obtained by the organic sampling portion of the project.

APPENDIX I

FUEL ANALYSIS RESULTS: FULL-SCALE TEST

TABLE I-1. RESULTS OF DIESEL FUEL 2 ANALYSIS

TEST	RESULTS
FLASH PT, DEG C(F)	80 (176)
SULFUR, %	.30
HEAT OF COMBUSTION, BTU/GAL	140,720
API GRAVITY	31.8
% BY WEIGHT: CARBON	87.08
% BY WEIGHT: HYDROGEN	12.96
% BY WEIGHT: NITROGEN	0.05

TABLE I-2. RESULTS OF JP-8 ANALYSIS

METHOD	TEST	RESULT	MIN	MAX
D4176	WATER & SEDIMENT, VISUAL	C&B		C&B
D156	COLOR, SAYBOLT	+30		REPORT
D3242	TOTAL ACID NUMBER, MG KOH/G	0.0		0.015
D1319	AROMATICS, VOL %	23.5		25.0
D1319	OLEFINS, VOL%	1.2		5.0
D235	DOCTOR TEST	P		NEG
D4294	TOTAL SULFUR, WT %	0.02		0.40
D86	DISTILLATION 1BP DEG C	180.2		REPORT
D86	DISTILLATION 10% DEG C	199.3		205
D86	DISTILLATION 20% DEG C	205.5		REPORT
D86	DISTILLATION 50% DEG C	220.0		REPORT
D86	DISTILLATION 90% DEG C	242.7		REPORT
D86	DISTILLATION EBP DEG C	254		350

METHOD	TEST	RESULT	MIN	MAX
D86	DISTILLATION RESIDUE, VOL %	1.1		1.5
D86	DISTILLATION LOSS, VOL %	1.1		1.5
D93	FLASH POINT, DEG F	148	100	
D1298	API GRAVITY	439.1	37.0	51.0
D1298	DENSITY, KG/L @ 15 DEG C	0.8294	0.775	0.840
D2386	FREEZING POINT, DEG C	-47		-47
D445	VISCOSITY AT -20 DEG C, CST	6.04		8.0
D3383	HEAT OF COMBUSTION, MJ/KG	42.97	42.80	
D3343	HYDROGEN CONTENT, WT %	13.56	13.4	
D1322	SMOKE POINT, MM	19.0	19	
D976	CETANE INDEX, CALCULATED	40.9		REPORT
D130	COPPER STRIP CORROSION	1B		1
D3241	THERMAL STABILITY, PD, MM HG	0		25
D3241	THERMAL STABILITY TUBE CODE	1		<3
D3241	THERMAL STABILITY, TDR	2		REPORT
D381	EXISTENT GUM, MG/100 ML	0.3		7.0
D2276	PARTICULATE MATTER, MG/L	0.0		1.0
SPEC	FILTRATION TIME, MIN	6		15
D1094	WATER RXN RATING, MAX	1B		1B
D1840	NAPTHALENES, VOL %	0.4		3.0
D3048	WSIM, MIN	91		70
	ANTIOXIDANT, MG/L	21.7	17.2	24
	CORROSION INHIBITOR, MG/L	19.3	14	22.5

APPENDIX J

FULL-SCALE TEST OPERATIONAL ANALYSIS AND RESULTS

The boiler performance data and efficiencies reported in this appendix are based on the input-output method and the heat-loss method. These methods are detailed in Appendix F. The steam, blow-down, and feedwater properties were calculated from the steam pressure and feedwater temperature using a proprietary computerized library, based on ASME STEAM TABLES, Fifth Edition 1983 (15).

The feedwater flow rate measurements were inaccurate, therefore the steam flow rate measurements were used in calculating the boiler capacity. The steam mass flow rate was also corrected to account for the difference between the measured steam pressure and the boiler rated pressure of 125 psig. The corrected steam mass flow rate is calculated from the following equation :

$$\textit{Steam Flow Rate (in pph)} = \textit{Measured Flow Rate (in pph)} \times \frac{Vg(Pr)}{Vg(Pm)} \quad \textbf{(J-1)}$$

where Vg(Pr) is the steam specific volume calculated at boiler rated pressure Pr in psia, and Vg(Pm) is the steam specific volume calculated at the measured steam pressure in psia.

The boiler performance data is given in six sets: J-1) diesel baseline for steam-atomized fuel operations; J-2) diesel baseline for air-atomized fuel operations; J-3) JP-8 baseline for steam-atomizing fuel operations; J-4) JP-8 baseline for air-atomized fuel operations; J-5) JP-8 performance for steam-atomized fuel operations; and J-6) JP-8 performance for air-atomized fuel operations. Each set includes the boiler performance data for 20, 40, 60, 80, and 100 percent load cases, with the exception of air-atomized fuel at 100 percent load. In all these sets the boiler capacity was calculated using the economizer feedwater inlet temperature while the combustion analysis was conducted using the economizer flue gases outlet temperature.

Summaries of boiler performance data and analyses follow. The format of the printed data does not reflect the accuracy of instrumentation used in these tests.

TABLE J-1.1. FULL-SCALE DF-2 BASELINE TEST, 20% LOAD, STEAM ATOMIZING, MAY 22, 1991

BOILER PERFORMANCE

Using Input-Output Method			
Boiler Capacity	=	7751074.96	BTU/hr
Heat input From Fuel	=	9456384.00	BTU/hr
Boiler Capacity	=	115343.38	BTU/gal. fuel
Boiler Thermal Efficiency	=	81.97	%
Using Heat Loss Method			
Combustion Analysis :			
Excess Air	=	1.2324	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	650.84	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1287.09	BTU/lb fuel
Air Humidity Loss	=	12.37	BTU/lb fuel
CO Loss	=	1.60	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	90.04	%
INPUT DATA :			
Steam :			
Flow Rate	=	7662.73	lb/hr
Pressure	=	108.00	psi
Enthalpy	=	1190.76	BTU/lb
Feedwater:			
Flow Rate	=	7500.00	lb/hr
Economizer Inlet Temp.	=	213.00	F
Economizer Outlet Temp.	=	236.70	F
Enthalpy (At Econ. Inlet Temp.)	=	181.17	BTU/lb
Fuel:			
Mass Flow Rate	=	483.20	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	1.12	gpm
Total Flow	=	67.00	gal
Pressure At Nozzle	=	30.00	psi
Pump Discharge Pressure	=	121.30	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	60.00	psi
Air:			
Dry Bulb Temp.	=	90.00	F
Wet Bulb Temp.	=	70.70	F
Humidity Ratio	=	.0117	lb H2O/lb dry air
Relative Humidity	=	37.56	%
Blow Down:			
Flow Rate	=	15.00	gal
Enthalpy	=	314.34	BTU/lb
Stack:			
Opacity	=	3.3000	%
Economizer Inlet Temp.	=	349.5000	F
Economizer Outlet Temp.	=	244.3000	F
O2	=	4.1800	%
CO	=	2.2500	ppm
NO2	=	77.8200	ppm
CO2 (calculated)	=	12.4305	%

TABLE J-1.2. FULL-SCALE DF-2 BASELINE TEST, 40% LOAD, STEAM ATOMIZING, MAY 22, 1991

BOILER PERFORMANCE

Usir Input-Output Method

Boiler Capacity	=	9663886.96	BTU/hr
Heat Input From Fuel	=	13171392.00	BTU/hr
Boiler Capacity	=	103246.66	BTU/gal. fuel
Boiler Thermal Efficiency	=	73.37	%

Using Heat Losses Method

Combustion Analysis :			
Excess Air	=	1.1207	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	611.17	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1285.99	BTU/lb fuel
Air Humidity Loss	=	12.47	BTU/lb fuel
CO Loss	=	2.62	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	90.23	%

INPUT DATA :

Steam :			
Flow Rate	=	9553.57	lb/hr
Pressure	=	110.80	psi
Enthalpy	=	1191.14	BTU/lb
Feedwater:			
Flow Rate	=	8150.00	lb/hr
Economizer Inlet Temp.	=	213.00	F
Economizer Outlet Temp.	=	240.30	F
Enthalpy (At Econ. Inlet Temp.)	=	181.17	BTU/lb
Fuel:			
Mass Flow Rate	=	673.03	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	1.56	gpm
Total Flow	=	110.00	gal
Pressure At Nozzle	=	34.30	psi
Pump Discharge Pressure	=	106.50	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	60.00	psi
Air:			
Dry Bulb Temp.	=	96.20	F
Wet Bulb Temp.	=	73.50	F
Humidity Ratio	=	.0125	lb H2O/lb dry air
Relative Humidity	=	32.89	%
Blow Down:			
Flow Rate	=	15.00	gal
Enthalpy	=	316.13	BTU/lb
Stack:			
Opacity	=	2.5000	%
Economizer Inlet Temp.	=	369.0000	F
Economizer Outlet Temp.	=	255.7000	F
O2	=	2.4000	%
CO	=	4.0700	ppm
NO2	=	78.6000	ppm
CO2 (calculated)	=	13.7449	%

TABLE J-1.3. FULL-SCALE DF-2 BASELINE TEST, 60% LOAD, STEAM ATOMIZING, MAY 22, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	10296403.35	BTU/hr
Heat Input From Fuel	=	14775600.00	BTU/hr
Boiler Capacity	=	98060.98	BTU/gal. fuel
Boiler Thermal Efficiency	=	69.69	%

Using Heat Losses Method

Combustion Analysis :

Excess Air	=	1.2422	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	721.96	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1288.97	BTU/lb fuel
Air Humidity Loss	=	14.52	BTU/lb fuel
CO Loss	=	1.73	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.64	%

INPUT DATA :

Steam :

Flow Rate	=	10220.62	lb/hr
Pressure	=	97.40	psi
Enthalpy	=	1189.19	BTU/lb

Feedwater:

Flow Rate	=	11200.00	lb/hr
Economizer Inlet Temp.	=	213.60	F
Economizer Outlet Temp.	=	243.80	F
Enthalpy (At Econ. Inlet Temp.)	=	181.78	BTU/lb

Fuel:

Mass Flow Rate	=	755.00	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	1.75	gpm
Total Flow	=	70.00	gal
Pressure At Nozzle	=	39.00	psi
Pump Discharge Pressure	=	107.00	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	60.00	psi

Air:

Dry Bulb Temp.	=	100.20	F
Wet Bulb Temp.	=	74.40	F
Humidity Ratio	=	.0123	lb H2O/lb dry air
Relative Humidity	=	28.52	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	1.0000	%
Economizer Inlet Temp.	=	387.2000	F
Economizer Outlet Temp.	=	270.0000	F
O2	=	4.3200	%
CO	=	2.4200	ppm
NO2	=	86.5800	ppm
CO2 (calculated)	=	12.3270	%

TABLE J-1.4. FULL-SCALE DF-2 BASELINE TEST, 80% LOAD, STEAM ATOMIZING, MAY 22, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	14634087.54	BTU/hr
Heat Input From Fuel	=	20263680.00	BTU/hr
Boiler Capacity	=	101625.61	BTU/gal. fuel
Boiler Thermal Efficiency	=	72.22	%

Using Heat Losses Method

Combustion Analysis :			
Excess Air	=	1.2133	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	768.93	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1296.80	BTU/lb fuel
Air Humidity Loss	=	16.16	BTU/lb fuel
CO Loss	=	1.90	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.34	%

INPUT DATA :

Steam :			
Flow Rate	=	14411.24	lb/hr
Pressure	=	117.40	psi
Enthalpy	=	1192.00	BTU/lb
Feedwater:			
Flow Rate	=	18250.00	lb/hr
Economizer Inlet Temp.	=	208.40	F
Economizer Outlet Temp.	=	242.30	F
Enthalpy (At Econ. Inlet Temp.)	=	176.54	BTU/lb
Fuel:			
Mass Flow Rate	=	1035.43	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	2.40	gpm
Total Flow	=	96.00	gal
Pressure At Nozzle	=	47.20	psi
Pump Discharge Pressure	=	106.00	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	60.00	psi
Air:			
Dry Bulb Temp.	=	100.80	F
Wet Bulb Temp.	=	75.20	F
Humidity Ratio	=	.0129	lb H2O/lb dry air
Relative Humidity	=	29.23	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	0.00	BTU/lb
Stack:			
Opacity	=	1.4000	%
Economizer Inlet Temp.	=	418.6000	F
Economizer Outlet Temp.	=	286.0000	F
O2	=	3.9000	%
CO	=	2.7200	ppm
NO2	=	77.6000	ppm
CO2 (calculated)	=	12.6372	%

TABLE J-1.5. FULL-SCALE DF-2 BASELINE TEST, 100% LOAD, STEAM ATOMIZING, JUNE 6, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	20661153.89	BTU/hr
Heat Input From Fuel	=	26427216.00	BTU/hr
Boiler Capacity	=	110016.79	BTU/gal. fuel
Boiler Thermal Efficiency	=	78.18	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2696	
Carbon Dioxide	=	.0725	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	937.54	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1314.61	BTU/lb fuel
Air Humidity Loss	=	17.73	BTU/lb fuel
CO Loss	=	.95	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	88.38	%

INPUT DATA :

Steam :

Flow Rate	=	20357.96	lb/hr
Pressure	=	126.00	psi
Enthalpy	=	1193.04	BTU/lb

Feedwater:

Flow Rate	=	19630.00	lb/hr
Economizer Inlet Temp.	=	210.00	F
Economizer Outlet Temp.	=	252.00	F
Enthalpy (At Econ. Inlet Temp.)	=	178.15	BTU/lb

Fuel:

Mass Flow Rate	=	1350.37	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	3.13	gpm
Pressure At Nozzle	=	55.00	psi
Pump Discharge Pressure	=	101.00	psi
Temperature	=	80.00	F
Atom. Fluid Pressure	=	75.00	psi

Air:

Dry Bulb Temp.	=	98.30	F
Wet Bulb Temp.	=	73.00	F
Humidity Ratio	=	.0116	lb H2O/lb dry air
Relative Humidity	=	28.51	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	.0000	%
Economizer Inlet Temp.	=	468.0000	F
Economizer Outlet Temp.	=	314.0000	F
O2	=	4.7000	%
CO	=	1.3000	ppm
NO2	=	70.7000	ppm
CO2 (calculated)	=	12.0478	%

TABLE J-2.1. FULL-SCALE DF-2 BASELINE TEST, 20% LOAD, AIR ATOMIZING, MAY 22, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	7697335.63	BTU/hr
Heat Input From Fuel	=	9794112.00	BTU/hr
Boiler Capacity	=	110593.90	BTU/gal. fuel
Boiler Thermal Efficiency	=	78.59	%

Using Heat Loss Method

Combustion Analysis :			
Excess Air	=	1.2543	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	647.93	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1277.09	BTU/lb fuel
Air Humidity Loss	=	13.89	BTU/lb fuel
CO Loss	=	1.31	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	90.08	%

INPUT DATA :

Steam :			
Flow Rate	=	7614.84	lb/hr
Pressure	=	112.00	psi
Enthalpy	=	1191.30	BTU/lb
Feedwater:			
Flow Rate	=	6750.00	lb/hr
Economizer Inlet Temp.	=	212.30	F
Economizer Outlet Temp.	=	244.40	F
Enthalpy (At Econ. Inlet Temp.)	=	180.47	BTU/lb
Fuel:			
Mass Flow Rate	=	500.46	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	1.16	gpm
Total Flow	=	70.00	gal
Pressure At Nozzle	=	35.14	psi
Pump Discharge Pressure	=	100.70	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	.00	psi
Air:			
Dry Bulb Temp.	=	103.10	F
Wet Bulb Temp.	=	76.10	F
Humidity Ratio	=	.0131	lb H2O/lb dry air
Relative Humidity	=	27.70	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	2.0000	%
Economizer Inlet Temp.	=	362.0000	F
Economizer Outlet Temp.	=	254.0000	F
O2	=	4.4900	%
CO	=	1.8100	ppm
NO2	=	111.5400	ppm
CO2 (calculated)	=	12.2017	%

TABLE J-2.2. FULL-SCALE DF-2 BASELINE TEST, 40% LOAD, AIR ATOMIZING, MAY 22, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	10776456.26	BTU/hr
Heat Input From Fuel	=	14522304.00	BTU/hr
Boiler Capacity	=	104423.03	BTU/gal. fuel
Boiler Thermal Efficiency	=	74.21	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.1173	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	585.25	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1276.75	BTU/lb fuel
Air Humidity Loss	=	13.12	BTU/lb fuel
CO Loss	=	2.08	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	90.40	%

INPUT DATA :

Steam :

Flow Rate	=	10671.89	lb/hr
Pressure	=	123.80	psi
Enthalpy	=	1192.79	BTU/lb

Feedwater:

Flow Rate	=	3550.00	lb/hr
Economizer Inlet Temp.	=	214.80	F
Economizer Outlet Temp.	=	243.40	F
Enthalpy (At Econ. Inlet Temp.)	=	182.99	BTU/lb

Fuel:

Mass Flow Rate	=	742.06	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	1.72	gpm
Total Flow	=	86.00	gal
Pressure At Nozzle	=	44.40	psi
Pump Discharge Pressure	=	101.60	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	.00	psi

Air:

Dry Bulb Temp.	=	105.60	F
Wet Bulb Temp.	=	77.40	F
Humidity Ratio	=	.0137	lb H2O/lb dry air
Relative Humidity	=	26.73	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	1.0000	%
Economizer Inlet Temp.	=	370.6000	F
Economizer Outlet Temp.	=	258.8000	F
O2	=	2.3400	%
CO	=	3.2400	ppm
NO2	=	95.6000	ppm
CO2 (calculated)	=	13.7898	%

TABLE J-2.3. FULL-SCALE DF-2 BASELINE TEST, 60% LOAD, AIR ATOMIZING, MAY 22, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	11747714.74	BTU/hr
Heat Input From Fuel	=	15873216.00	BTU/hr
Boiler Capacity	=	104146.41	BTU/gal. fuel
Boiler Thermal Efficiency	=	74.01	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2565	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	732.94	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1286.10	BTU/lb fuel
Air Humidity Loss	=	16.83	BTU/lb fuel
CO Loss	=	1.27	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.59	%

INPUT DATA :

Steam :

Flow Rate	=	11671.84	lb/hr
Pressure	=	123.20	psi
Enthalpy	=	1192.71	BTU/lb

Feedwater:

Flow Rate	=	3717.00	lb/hr
Economizer Inlet Temp.	=	218.00	F
Economizer Outlet Temp.	=	251.50	F
Enthalpy (At Econ. Inlet Temp.)	=	186.21	BTU/lb

Fuel:

Mass Flow Rate	=	811.09	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	1.88	gpm
Total Flow	=	113.00	gal
Pressure At Nozzle	=	50.00	psi
Pump Discharge Pressure	=	103.30	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	.00	psi

Air:

Dry Bulb Temp.	=	105.30	F
Wet Bulb Temp.	=	77.70	F
Humidity Ratio	=	.0141	lb H2O/lb dry air
Relative Humidity	=	27.66	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	1.0000	%
Economizer Inlet Temp.	=	398.8000	F
Economizer Outlet Temp.	=	275.7000	F
O2	=	4.5200	%
CO	=	1.7500	ppm
NO2	=	119.7000	ppm
CO2 (calculated)	=	12.1796	%

TABLE J-2.4. FULL-SCALE DF-2 BASELINE TEST, 90% LOAD, AIR ATOMIZING, MAY 22,1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	14536932.55	BTU/hr
Heat Input From Fuel	=	19588224.00	BTU/hr
Boiler Capacity	=	104431.99	BTU/gal. fuel
Boiler Thermal Efficiency	=	74.21	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2352	
Carbon Dioxide	=	.0724	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	779.15	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1293.26	BTU/lb fuel
Air Humidity Loss	=	17.54	BTU/lb fuel
CO Loss	=	1.37	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.31	%

INPUT DATA :

Steam :

Flow Rate	=	14469.63	lb/hr
Pressure	=	111.00	psi
Enthalpy	=	1191.17	BTU/lb

Feedwater:

Flow Rate	=	5058.00	lb/hr
Economizer Inlet Temp.	=	218.30	F
Economizer Outlet Temp.	=	252.50	F
Enthalpy (At Econ. Inlet Temp.)	=	186.52	BTU/lb

Fuel:

Mass Flow Rate .	=	1000.92	lb/hr
High-Heat Value	=	140720.00	BTU/gal
High-Heat Value	=	19570.30	BTU/lb
Flow Rate	=	2.32	gpm
Total Flow	=	116.00	gal
Pressure At Nozzle	=	63.30	psi
Pump Discharge Pressure	=	104.20	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	.00	psi

Air:

Dry Bulb Temp.	=	105.70	F
Wet Bulb Temp.	=	77.50	F
Humidity Ratio	=	.0138	lb H_2O/lb dry air
Relative Humidity	=	26.77	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	1.0000	%
Economizer Inlet Temp.	=	421.2000	F
Economizer Outlet Temp.	=	290.0000	F
O_2	=	4.2200	%
CO	=	1.9200	ppm
NO_2	=	110.8000	ppm
CO_2 (calculated)	=	12.4012	%

TABLE J-3.1. FULL-SCALE JP-8 BASELINE TEST, 20% LOAD, STEAM ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	6457039.47	BTU/hr
Heat Input From Fuel	=	8977527.00	BTU/hr
Boiler Capacity	=	91980.62	BTU/gal. fuel
Boiler Thermal Efficiency	=	71.92	%

Using Heat Loss Method

Combustion Analysis :			
Excess Air	=	1.2610	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	717.49	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1345.25	BTU/lb fuel
Air Humidity Loss	=	14.38	BTU/lb fuel
CO Loss	=	1.38	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.16	%

INPUT DATA :

Steam :			
Flow Rate	=	6393.12	lb/hr
Pressure	=	118.00	psi
Enthalpy	=	1192.08	BTU/lb
Feedwater:			
Flow Rate	=	5743.00	lb/hr
Economizer Inlet Temp.	=	213.90	F
Economizer Outlet Temp.	=	248.70	F
Enthalpy (At Econ. Inlet Temp.)	=	182.08	BTU/lb
Fuel:			
Mass Flow Rate	=	468.58	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19159.01	BTU/lb
Flow Rate	=	1.17	gpm
Total Flow	=	70.00	gal
Pressure At Nozzle	=	28.60	psi
Pump Discharge Pressure	=	100.00	psi
Temperature	=	90.00	F
Atom. Fluid Pressure	=	59.00	psi
Air:			
Dry Bulb Temp.	=	85.00	F
Wet Bulb Temp.	=	70.00	F
Humidity Ratio	=	.0123	lb H2O/lb dry air
Relative Humidity	=	46.64	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	.0000	%
Economizer Inlet Temp.	=	354.4000	F
Economizer Outlet Temp.	=	250.6000	F
O2	=	4.5900	%
CO	=	1.8900	ppm
NO2	=	69.0000	ppm
CO2 (calculated)	=	11.9898	%

TABLE J-3.2. FULL-SCALE JP-8 BASELINE TEST, 40% LOAD, STEAM ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	10963445.39	BTU/hr
Heat Input From Fuel	=	12430422.00	BTU/hr
Boiler Capacity	=	112792.65	BTU/gal. fuel
Boiler Thermal Efficiency	=	88.20	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.1193	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	647.03	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1345.03	BTU/lb fuel
Air Humidity Loss	=	13.30	BTU/lb fuel
CO Loss	=	1.66	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.53	%

INPUT DATA :

Steam :

Flow Rate	=	10817.88	lb/hr
Pressure	=	120.70	psi
Enthalpy	=	1192.41	BTU/lb

Feedwater:

Flow Rate	=	9166.70	lb/hr
Economizer Inlet Temp.	=	210.80	F
Economizer Outlet Temp.	=	240.30	F
Enthalpy (At Econ. Inlet Temp.)	=	178.96	BTU/lb

Fuel:

Mass Flow Rate	=	648.80	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19159.01	BTU/lb
Flow Rate	=	1.62	gpm
Total Flow	=	81.00	gal
Pressure At Nozzle	=	35.00	psi
Pump Discharge Pressure	=	100.70	psi
Temperature	=	90.00	F
Atom. Fluid Pressure	=	63.50	psi

Air:

Dry Bulb Temp.	=	87.80	F
Wet Bulb Temp.	=	71.20	F
Humidity Ratio	=	.0126	lb H2O/lb dry air
Relative Humidity	=	43.52	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	.0000	%
Economizer Inlet Temp.	=	379.0000	F
Economizer Outlet Temp.	=	256.3000	F
O2	=	2.3800	%
CO	=	2.5700	ppm
NO2	=	71.0000	ppm
CO2 (calculated)	=	13.6042	%

TABLE J-3.3. FULL-SCALE JP-8 BASELINE TEST, 60% LOAD, STEAM ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	11782288.59	BTU/hr
Heat Input From Fuel	=	13965042.00	BTU/hr
Boiler Capacity	=	107896.42	BTU/gal. fuel
Boiler Thermal Efficiency	=	84.37	%

Using Heat Loss Method

Combustion Analysis :			
Excess Air	=	1.2787	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	796.62	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1350.49	BTU/lb fuel
Air Humidity Loss	=	17.08	BTU/lb fuel
CO Loss	=	1.10	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	88.70	%

INPUT DATA :

Steam :			
Flow Rate	=	11677.40	lb/hr
Pressure	=	114.00	psi
Enthalpy	=	1191.57	BTU/lb
Feedwater:			
Flow Rate	=	10714.00	lb/hr
Economizer Inlet Temp.	=	214.40	F
Economizer Outlet Temp.	=	248.00	F
Enthalpy (At Econ. Inlet Temp.)	=	182.58	BTU/lb
Fuel:			
Mass Flow Rate	=	728.90	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19159.01	BTU/lb
Flow Rate	=	1.82	gpm
Total Flow	=	109.00	gal
Pressure At Nozzle	=	38.10	psi
Pump Discharge Pressure	=	101.70	psi
Temperature	=	90.00	F
Atom. Fluid Pressure	=	63.90	psi
Air:			
Dry Bulb Temp.	=	90.30	F
Wet Bulb Temp.	=	72.60	F
Humidity Ratio	=	.0131	lb H2O/lb dry air
Relative Humidity	=	41.85	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	.0000	%
Economizer Inlet Temp.	=	396.9000	F
Economizer Outlet Temp.	=	271.6000	F
O2	=	4.8300	%
CO	=	1.4800	ppm
NO2	=	80.8000	ppm
CO2 (calculated)	=	11.8158	%

TABLE J-3.4. FULL-SCALE JP-8 BASELINE TEST, 80% LOAD, STEAM ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	14703346.60	BTU/hr
Heat Input From Fuel	=	17111013.00	BTU/hr
Boiler Capacity	=	109890.48	BTU/gal. fuel
Boiler Thermal Efficiency	=	85.93	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2149	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	810.66	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1355.21	BTU/lb fuel
Air Humidity Loss	=	18.22	BTU/lb fuel
CO Loss	=	1.26	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	88.59	%

INPUT DATA :

Steam :			
Flow Rate	=	14530.51	lb/hr
Pressure	=	114.70	psi
Enthalpy	=	1191.66	BTU/lb
Feedwater:			
Flow Rate	=	13310.00	lb/hr
Economizer Inlet Temp.	=	211.60	F
Economizer Outlet Temp.	=	248.90	F
Enthalpy (At Econ. Inlet Temp.)	=	179.76	BTU/lb
Fuel:			
Mass Flow Rate	=	893.11	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19159.01	BTU/lb
Flow Rate	=	2.23	gpm
Total Flow	=	134.00	gal
Pressure At Nozzle	=	48.60	psi
Pump Discharge Pressure	=	100.30	psi
Temperature	=	90.00	F
Atom. Fluid Pressure	=	70.70	psi
Air:			
Dry Bulb Temp.	=	94.10	F
Wet Bulb Temp.	=	74.40	F
Humidity Ratio	=	.0137	lb H2O/lb dry air
Relative Humidity	=	38.73	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	.0000	%
Economizer Inlet Temp.	=	426.4000	F
Economizer Outlet Temp.	=	288.4000	F
O2	=	3.9300	%
CO	=	1.7900	ppm
NO2	=	69.0000	ppm
CO2 (calculated)	=	12.4721	%

TABLE J-3.5. FULL-SCALE JP-8 BASELINE TEST, 100% LOAD, STEAM ATOMIZING, JUNE 6, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	20471767.87	BTU/hr
Heat Input From Fuel	=	25014306.00	BTU/hr
Boiler Capacity	=	104661.39	BTU/gal. fuel
Boiler Thermal Efficiency	=	81.84	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.3150	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	1008.04	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1372.44	BTU/lb fuel
Air Humidity Loss	=	16.78	BTU/lb fuel
CO Loss	=	1.49	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	87.39	%

INPUT DATA :

Steam :			
Flow Rate	=	20143.32	lb/hr
Pressure	=	124.30	psi
Enthalpy	=	1192.85	BTU/lb
Feedwater:			
Flow Rate	=	19380.00	lb/hr
Economizer Inlet Temp.	=	208.40	F
Economizer Outlet Temp.	=	252.00	F
Enthalpy (At Econ. Inlet Temp.)	=	176.54	BTU/lb
Fuel:			
Mass Flow Rate	=	1313.16	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19048.91	BTU/lb
Flow Rate	=	3.26	gpm
Total Flow	=	750.00	gal
Pressure At Nozzle	=	59.00	psi
Pump Discharge Pressure	=	98.00	psi
Temperature	=	81.00	F
Atom. Fluid Pressure	=	78.00	psi
Air:			
Dry Bulb Temp.	=	92.00	F
Wet Bulb Temp.	=	69.40	F
Humidity Ratio	=	.0102	lb H2O/lb dry air
Relative Humidity	=	30.74	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	.0000	%
Economizer Inlet Temp.	=	472.0000	F
Economizer Outlet Temp.	=	315.0000	F
O2	=	5.3000	%
CO	=	1.9500	ppm
NO2	=	60.5000	ppm
CO2 (calculated)	=	11.4709	%

TABLE J-4.1. FULL-SCALE JP-8 BASELINE TEST, 20% LOAD, AIR ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	8032581.05	BTU/hr
Heat Input From Fuel	=	9054258.00	BTU/hr
Boiler Capacity	=	113454.53	BTU/gal. fuel
Boiler Thermal Efficiency	=	88.72	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2502	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	665.27	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1332.13	BTU/lb fuel
Air Humidity Loss	=	15.48	BTU/lb fuel
CO Loss	=	.90	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.54	%

INPUT DATA :

Steam :			
Flow Rate	=	7960.88	lb/hr
Pressure	=	110.40	psi
Enthalpy	=	1191.09	BTU/lb
Feedwater:			
Flow Rate	=	6993.00	lb/hr
Economizer Inlet Temp.	=	213.90	F
Economizer Outlet Temp.	=	242.30	F
Enthalpy (At Econ. Inlet Temp.)	=	182.08	BTU/lb
Fuel:			
Mass Flow Rate	=	469.97	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19265.41	BTU/lb
Flow Rate	=	1.18	gpm
Total Flow	=	.00	gal
Pressure At Nozzle	=	33.40	psi
Pump Discharge Pressure	=	101.70	psi
Temperature	=	98.60	F
Atom. Fluid Pressure	=	59.30	psi
Air:			
Dry Bulb Temp.	=	96.10	F
Wet Bulb Temp.	=	75.50	F
Humidity Ratio	=	.0142	lb H2O/lb dry air
Relative Humidity	=	37.59	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	.0000	%
Economizer Inlet Temp.	=	361.1000	F
Economizer Outlet Temp.	=	251.0000	F
O2	=	4.4400	%
CO	=	1.2400	ppm
NO2	=	95.6300	ppm
CO2 (calculated)	=	12.1007	%

TABLE J-4.2. FULL-SCALE JP-8 BASELINE TEST, 40% LOAD, AIR ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	10138644.57	BTU/hr
Heat Input From Fuel	=	12660615.00	BTU/hr
Boiler Capacity	=	102410.55	BTU/gal. fuel
Boiler Thermal Efficiency	=	80.08	%

Using Heat Loss Method

Combustion Analysis :			
Excess Air	=	1.1394	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	630.66	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1334.17	BTU/lb fuel
Air Humidity Loss	=	14.88	BTU/lb fuel
CO Loss	=	.95	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.72	%

INPUT DATA :

Steam :			
Flow Rate	=	10111.35	lb/hr
Pressure	=	110.00	psi
Enthalpy	=	1191.03	BTU/lb
Feedwater:			
Flow Rate	=	8926.00	lb/hr
Economizer Inlet Temp.	=	220.10	F
Economizer Outlet Temp.	=	245.70	F
Enthalpy (At Econ. Inlet Temp.)	=	188.33	BTU/lb
Fuel:			
Mass Flow Rate	=	656.57	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19282.84	BTU/lb
Flow Rate	=	1.65	gpm
Total Flow	=	99.00	gal
Pressure At Nozzle	=	40.90	psi
Pump Discharge Pressure	=	101.40	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	62.00	psi
Air:			
Dry Bulb Temp.	=	98.40	F
Wet Bulb Temp.	=	76.30	F
Humidity Ratio	=	.0144	lb H2O/lb dry air
Relative Humidity	=	35.32	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	.0000	%
Economizer Inlet Temp.	=	373.4000	F
Economizer Outlet Temp.	=	259.7000	F
O2	=	2.7300	%
CO	=	1.4400	ppm
NO2	=	98.5000	ppm
CO2 (calculated)	=	13.3503	%

TABLE J-4.3. FULL-SCALE JP-8 BASELINE TEST, 60% LOAD, AIR ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	11592355.11	BTU/hr
Heat Input From Fuel	=	14195235.00	BTU/hr
Boiler Capacity	=	104435.63	BTU/gal. fuel
Boiler Thermal Efficiency	=	81.66	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2886	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	776.31	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1341.07	BTU/lb fuel
Air Humidity Loss	=	17.22	BTU/lb fuel
CO Loss	=	1.23	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	88.92	%

INPUT DATA :

Steam :

Flow Rate	=	11549.69	lb/hr
Pressure	=	116.00	psi
Enthalpy	=	1191.82	BTU/lb

Feedwater:

Flow Rate	=	10214.30	lb/hr
Economizer Inlet Temp.	=	219.90	F
Economizer Outlet Temp.	=	253.60	F
Enthalpy (At Econ. Inlet Temp.)	=	188.13	BTU/lb

Fuel:

Mass Flow Rate	=	736.16	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19282.84	BTU/lb
Flow Rate	=	1.85	gpm
Total Flow	=	111.00	gal
Pressure At Nozzle	=	48.00	psi
Pump Discharge Pressure	=	101.60	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	63.50	psi

Air:

Dry Bulb Temp.	=	99.70	F
Wet Bulb Temp.	=	75.70	F
Humidity Ratio	=	.0136	lb H2O/lb dry air
Relative Humidity	=	31.91	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	.0000	%
Economizer Inlet Temp.	=	398.0000	F
Economizer Outlet Temp.	=	275.0000	F
O2	=	4.9600	%
CO	=	1.6400	ppm
NO2	=	120.3000	ppm
CO2 (calculated)	=	11.7196	%

TABLE J-4.4. FULL-SCALE JP-8 BASELINE TEST, 80% LOAD, AIR ATOMIZING, MAY 28, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	14269947.72	BTU/hr
Heat Input From Fuel	=	19029288.00	BTU/hr
Boiler Capacity	=	95900.19	BTU/gal. fuel
Boiler Thermal Efficiency	=	74.99	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2466	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	823.50	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1352.03	BTU/lb fuel
Air Humidity Loss	=	19.75	BTU/lb fuel
CO Loss	=	1.13	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	88.61	%

INPUT DATA :

Steam :

Flow Rate	=	14217.59	lb/hr
Pressure	=	111.30	psi
Enthalpy	=	1191.21	BTU/lb

Feedwater:

Flow Rate	=	15649.00	lb/hr
Economizer Inlet Temp.	=	219.30	F
Economizer Outlet Temp.	=	253.00	F
Enthalpy (At Econ. Inlet Temp.)	=	187.53	BTU/lb

Fuel:

Mass Flow Rate	=	986.85	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19282.84	BTU/lb
Flow Rate	=	2.48	gpm
Total Flow	=	124.00	gal
Pressure At Nozzle	=	62.30	psi
Pump Discharge Pressure	=	100.60	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	62.00	psi

Air:

Dry Bulb Temp.	=	97.30	F
Wet Bulb Temp.	=	76.30	F
Humidity Ratio	=	.0147	lb H2O/lb dry air
Relative Humidity	=	37.25	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	.0000	%
Economizer Inlet Temp.	=	423.4000	F
Economizer Outlet Temp.	=	289.6000	F
O2	=	4.3900	%
CO	=	1.5600	ppm
NO2	=	106.1000	ppm
CO2 (calculated)	=	12.1373	%

TABLE J-5.1. FULL-SCALE JP-8 PERFORMANCE TEST, 20% LOAD, STEAM ATOMIZING, JUNE 1, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	6192003.69	BTU/hr
Heat Input From Fuel	=	7519638.00	BTU/hr
Boiler Capacity	=	105306.19	BTU/gal. fuel
Boiler Thermal Efficiency	=	82.34	%

Using Heat Loss Method

Combustion Analysis :			
Excess Air	=	1.4382	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	727.89	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1325.35	BTU/lb fuel
Air Humidity Loss	=	13.63	BTU/lb fuel
CO Loss	=	.92	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.25	%

INPUT DATA :

Steam :			
Flow Rate	=	6146.73	lb/hr
Pressure	=	125.40	psi
Enthalpy	=	1192.97	BTU/lb
Feedwater:			
Flow Rate	=	4286.00	lb/hr
Economizer Inlet Temp.	=	217.40	F
Economizer Outlet Temp.	=	248.40	F
Enthalpy (At Econ. Inlet Temp.)	=	185.61	BTU/lb
Fuel:			
Mass Flow Rate	=	391.15	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19224.44	BTU/lb
Flow Rate	=	.98	gpm
Total Flow	=	59.00	gal
Pressure At Nozzle	=	22.00	psi
Pump Discharge Pressure	=	98.00	psi
Temperature	=	95.30	F
Atom. Fluid Pressure	=	52.00	psi
Air:			
Dry Bulb Temp.	=	99.90	F
Wet Bulb Temp.	=	73.30	F
Humidity Ratio	=	.0115	lb H2O/lb dry air
Relative Humidity	=	26.80	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	4.3000	%
Economizer Inlet Temp.	=	357.1000	F
Economizer Outlet Temp.	=	247.0000	F
O2	=	6.7100	%
CO	=	1.0900	ppm
NO2	=	53.9000	ppm
CO2 (calculated)	=	10.4420	%

TABLE J-5.2. FULL-SCALE JP-8 PERFORMANCE TEST, 40% LOAD, STEAM ATOMIZING, JUNE 1, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	9350517.34	BTU/hr
Heat Input From Fuel	=	11125995.00	BTU/hr
Boiler Capacity	=	107477.21	BTU/gal. fuel
Boiler Thermal Efficiency	=	84.04	%

Using Heat Loss Method

Combustion Analysis :			
Excess Air	=	1.1873	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	633.05	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1327.42	BTU/lb fuel
Air Humidity Loss	=	11.46	BTU/lb fuel
CO Loss	=	.51	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.78	%

INPUT DATA :

Steam :			
Flow Rate	=	9290.94	lb/hr
Pressure	=	123.30	psi
Enthalpy	=	1192.73	BTU/lb
Feedwater:			
Flow Rate	=	8614.00	lb/hr
Economizer Inlet Temp.	=	218.10	F
Economizer Outlet Temp.	=	248.40	F
Enthalpy (At Econ. Inlet Temp.)	=	186.31	BTU/lb
Fuel:			
Mass Flow Rate	=	576.99	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19282.84	BTU/lb
Flow Rate	=	1.45	gpm
Total Flow	=	87.00	gal
Pressure At Nozzle	=	30.00	psi
Pump Discharge Pressure	=	98.00	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	57.10	psi
Air:			
Dry Bulb Temp.	=	103.70	F
Wet Bulb Temp.	=	73.86	F
Humidity Ratio	=	.0111	lb H2O/lb dry air
Relative Humidity	=	22.88	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	5.0000	%
Economizer Inlet Temp.	=	374.4000	F
Economizer Outlet Temp.	=	259.0000	F
O2	=	3.5100	%
CO	=	.7400	ppm
NO2	=	71.5300	ppm
CO2 (calculated)	=	12.7803	%

TABLE J-5.3. FULL-SCALE JP-8 PERFORMANCE TEST, 60% LOAD, STEAM ATOMIZING, JUNE 1, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	11229802.68	BTU/hr
Heat Input From Fuel	=	13274463.00	BTU/hr
Boiler Capacity	=	108186.92	BTU/gal. fuel
Boiler Thermal Efficiency	=	84.60	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.2993	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	736.39	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1330.32	BTU/lb fuel
Air Humidity Loss	=	13.32	BTU/lb fuel
CO Loss	=	.76	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.21	%

INPUT DATA :

Steam :

Flow Rate	=	11144.14	lb/hr
Pressure	=	124.70	psi
Enthalpy	=	1192.89	BTU/lb

Feedwater:

Flow Rate	=	9.90	lb/hr
Economizer Inlet Temp.	=	217.00	F
Economizer Outlet Temp.	=	251.40	F
Enthalpy (At Econ. Inlet Temp.)	=	185.21	BTU/lb

Fuel:

Mass Flow Rate	=	688.27	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19286.58	BTU/lb
Flow Rate	=	1.73	gpm
Total Flow	=	104.00	gal
Pressure At Nozzle	=	34.00	psi
Pump Discharge Pressure	=	98.00	psi
Temperature	=	100.30	F
Atom. Fluid Pressure	=	60.00	psi

Air:

Dry Bulb Temp.	=	107.40	F
Wet Bulb Temp.	=	74.86	F
Humidity Ratio	=	.0111	lb H2O/lb dry air
Relative Humidity	=	20.34	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	4.6700	%
Economizer Inlet Temp.	=	395.1000	F
Economizer Outlet Temp.	=	272.3000	F
O2	=	5.1000	%
CO	=	1.0100	ppm
NO2	=	71.3700	ppm
CO2 (calculated)	=	11.6185	%

TABLE J-5.4. FULL-SCALE JP-8 PERFORMANCE TEST, 80% LOAD, STEAM ATOMIZING, JUNE 1,1991

BOILER PERFORMANCE

Using Input-Output Method			
Boiler Capacity	=	16204183.87	BTU/hr
Heat Input From Fuel	=	19182750.00	BTU/hr
Boiler Capacity	=	108027.89	BTU/gal. fuel
Boiler Thermal Efficiency	=	84.47	%
Using Heat Loss Method			
Combustion Analysis :			
Excess Air	=	1.1746	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	718.10	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1335.35	BTU/lb fuel
Air Humidity Loss	=	13.54	BTU/lb fuel
CO Loss	=	1.15	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.27	%

INPUT DATA :

Steam :			
Flow Rate	=	16005.26	lb/hr
Pressure	=	125.60	psi
Enthalpy	=	1193.00	BTU/lb
Feedwater:			
Flow Pate	=	14829.00	lb/hr
Economizer Inlet Temp.	=	212.40	F
Economizer Outlet Temp.	=	249.40	F
Enthalpy (At Econ. Inlet Temp.)	=	180.57	BTU/lb
Fuel:			
Mass Flow Rate	=	994.81	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19282.84	BTU/lb
Flow Rate	=	2.50	gpm
Total Flow	=	150.00	gal
Pressure At Nozzle	=	46.10	psi
Pump Discharge Pressure	=	98.00	psi
Temperature	=	100.00	F
Atom. Fluid Pressure	=	68.00	psi
Air:			
Dry Bulb Temp.	=	110.90	F
Wet Bulb Temp.	=	76.30	F
Humidity Ratio	=	.0115	lb H2O/lb dry air
Relative Humidity	=	18.95	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	4.1400	%
Economizer Inlet Temp.	=	423.6000	F
Economizer Outlet Temp.	=	289.0000	F
O2	=	3.3100	%
CO	=	1.6900	ppm
NO2	=	68.0000	ppm
CO2 (calculated)	=	12.9265	%

TABLE J-5.5. FULL-SCALE JP-8 PERFORMANCE TEST, 100% LOAD, STEAM ATOMIZING, JUNE 5, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	20627932.36	BTU/hr
Heat Input From Fuel	=	25858347.00	BTU/hr
Boiler Capacity	=	102017.47	BTU/gal. fuel
Boiler Thermal Efficiency	=	79.77	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.1803	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0001	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	852.79	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1358.07	BTU/lb fuel
Air Humidity Loss	=	12.48	BTU/lb fuel
CO Loss	=	6.13	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	88.41	%

INPUT DATA :

Steam :

Flow Rate	=	20368.00	lb/hr
Pressure	=	125.00	psi
Enthalpy	=	1192.93	BTU/lb

Feedwater:

Flow Rate	=	25810.00	lb/hr
Economizer Inlet Temp.	=	212.00	F
Economizer Outlet Temp.	=	252.00	F
Enthalpy (At Econ. Inlet Temp.)	=	180.17	BTU/lb

Fuel:

Mass Flow Rate	=	1342.13	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19266.66	BTU/lb
Flow Rate	=	3.37	gpm
Total Flow	=	1113.00	gal
Pressure At Nozzle	=	62.00	psi
Pump Discharge Pressure	=	99.60	psi
Temperature	=	98.70	F
Atom. Fluid Pressure	=	78.00	psi

Air:

Dry Bulb Temp.	=	103.50	F
Wet Bulb Temp.	=	71.20	F
Humidity Ratio	=	.0089	lb H2O/lb dry air
Relative Humidity	=	18.62	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	.0000	%
Economizer Inlet Temp.	=	468.0000	F
Economizer Outlet Temp.	=	314.0000	F
O2	=	3.4000	%
CO	=	9.0000	ppm
NO2	=	66.7000	ppm
CO2 (calculated)	=	12.8543	%

TABLE J-6.1. FULL-SCALE JP-8 PERFORMANCE TEST, 20% LOAD, AIR ATOMIZING, JUNE 1, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	6275444.40	BTU/hr
Heat Input From Fuel	=	7442907.00	BTU/hr
Boiler Capacity	=	107825.51	BTU/gal. fuel
Boiler Thermal Efficiency	=	84.31	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.4027	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	655.69	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1309.94	BTU/lb fuel
Air Humidity Loss	=	12.22	BTU/lb fuel
CO Loss	=	.91	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.77	%

INPUT DATA :

Steam :

Flow Rate	=	6201.96	lb/hr
Pressure	=	122.40	psi
Enthalpy	=	1192.62	BTU/lb

Feedwater:

Flow Rate	=	4986.00	lb/hr
Economizer Inlet Temp.	=	212.60	F
Economizer Outlet Temp.	=	246.90	F
Enthalpy (At Econ. Inlet Temp.)	=	180.77	BTU/lb

Fuel:

Mass Flow Rate	=	384.74	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19345.36	BTU/lb
Flow Rate	=	.97	gpm
Total Flow	=	58.00	gal
Pressure At Nozzle	=	26.00	psi
Pump Discharge Pressure	=	98.00	psi
Temperature	=	105.00	F
Atom. Fluid Pressure	=	50.00	psi

Air:

Dry Bulb Temp.	=	114.10	F
Wet Bulb Temp.	=	77.00	F
Humidity Ratio	=	.0114	lb H_2O/lb dry air
Relative Humidity	=	16.96	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	4.1700	%
Economizer Inlet Temp.	=	312.3000	F
Economizer Outlet Temp.	=	250.0000	F
O_2	=	6.3300	%
CO	=	1.1100	ppm
NO_2	=	91.9000	ppm
CO_2 (calculated)	=	10.7197	%

TABLE J-6.2. FULL-SCALE JP-8 PERFORMANCE TEST, 40% LOAD, AIR ATOMIZING, JUNE 1, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	9364386.89	BTU/hr
Heat Input From Fuel	=	11356188.00	BTU/hr
Boiler Capacity	=	105454.81	BTU/gal. fuel
Boiler Thermal Efficiency	=	82.46	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.1778	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	572.92	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1314.06	BTU/lb fuel
Air Humidity Loss	=	10.75	BTU/lb fuel
CO Loss	=	.59	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	90.22	%

INPUT DATA :

Steam :

Flow Rate	=	9247.46	lb/hr
Pressure	=	124.00	psi
Enthalpy	=	1192.81	BTU/lb

Feedwater:

Flow Rate	=	8571.00	lb/hr
Economizer Inlet Temp.	=	212.00	F
Economizer Outlet Temp.	=	241.60	F
Enthalpy (At Econ. Inlet Temp.)	=	180.17	BTU/lb

Fuel:

Mass Flow Rate	=	585.12	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19408.29	BTU/lb
Flow Rate	=	1.48	gpm
Total Flow	=	89.00	gal
Pressure At Nozzle	=	38.00	psi
Pump Discharge Pressure	=	98.00	psi
Temperature	=	110.00	F
Atom. Fluid Pressure	=	56.60	psi

Air:

Dry Bulb Temp.	=	112.70	F
Wet Bulb Temp.	=	76.70	F
Humidity Ratio	=	.0115	lb H2O/lb dry air
Relative Humidity	=	17.81	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	.2900	%
Economizer Inlet Temp.	=	375.6000	F
Economizer Outlet Temp.	=	254.4000	F
O2	=	3.3600	%
CO	=	.8700	ppm
NO2	=	101.3000	ppm
CO2 (calculated)	=	12.8899	%

TABLE J-6.3. FULL-SCALE JP-8 PERFORMANCE TEST, 60% LOAD, AIR ATOMIZING, JUNE 1, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	10912581.16	BTU/hr
Heat Input From Fuel	=	12430422.00	BTU/hr
Boiler Capacity	=	112269.35	BTU/gal. fuel
Boiler Thermal Efficiency	=	87.79	%

Using Heat Loss Method

Combustion Analysis :			
Excess Air	=	1.2939	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel
Combustion Losses :			
Dry Gas Loss	=	691.48	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1320.91	BTU/lb fuel
Air Humidity Loss	=	13.05	BTU/lb fuel
CO Loss	=	.89	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.56	%

INPUT DATA :

Steam :			
Flow Rate	=	10774.00	lb/hr
Pressure	=	125.00	psi
Enthalpy	=	1192.93	BTU/lb
Feedwater:			
Flow Rate	=	9629.00	lb/hr
Economizer Inlet Temp.	=	211.90	F
Economizer Outlet Temp.	=	247.70	F
Enthalpy (At Econ. Inlet Temp.)	=	180.06	BTU/lb
Fuel:			
Mass Flow Rate	=	640.47	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19408.29	BTU/lb
Flow Rate	=	1.62	gpm
Total Flow	=	97.00	gal
Pressure At Nozzle	=	43.40	psi
Pump Discharge Pressure	=	99.00	psi
Temperature	=	110.00	F
Atom. Fluid Pressure	=	61.14	psi
Air:			
Dry Bulb Temp.	=	113.90	F
Wet Bulb Temp.	=	77.10	F
Humidity Ratio	=	.0115	lb H2O/lb dry air
Relative Humidity	=	17.27	%
Blow Down:			
Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb
Stack:			
Opacity	=	.0000	%
Economizer Inlet Temp.	=	387.0000	F
Economizer Outlet Temp.	=	269.4000	F
O2	=	5.0300	%
CO	=	1.1900	ppm
NO2	=	105.5000	ppm
CO2 (calculated)	=	11.6696	%

TABLE J-6.4. FULL-SCALE JP-8 PERFORMANCE TEST, 80% LOAD, AIR ATOMIZING, JUNE 1, 1991

BOILER PERFORMANCE

Using Input-Output Method

Boiler Capacity	=	16292985.29	BTU/hr
Heat Input From Fuel	=	20487177.00	BTU/hr
Boiler Capacity	=	101704.03	BTU/gal. fuel
Boiler Thermal Efficiency	=	79.53	%

Using Heat Loss Method

Combustion Analysis :

Excess Air	=	1.1436	
Carbon Dioxide	=	.0719	lb mol/lb fuel
Carbon Monoxide	=	.0000	lb mol/lb fuel

Combustion Losses :

Dry Gas Loss	=	681.65	BTU/lb fuel
Fuel Water Loss	=	.00	BTU/lb fuel
Fuel Hydrogen Loss	=	1327.47	BTU/lb fuel
Air Humidity Loss	=	13.88	BTU/lb fuel
CO Loss	=	.74	BTU/lb fuel
Radiation Loss	=	.00	BTU/lb fuel
Boiler Combustion Efficiency	=	89.53	%

INPUT DATA :

Steam :

Flow Rate	=	16184.73	lb/hr
Pressure	=	127.40	psi
Enthalpy	=	1193.21	BTU/lb

Feedwater:

Flow Rate	=	.00	lb/hr
Economizer Inlet Temp.	=	218.30	F
Economizer Outlet Temp.	=	252.30	F
Enthalpy (At Econ. Inlet Temp.)	=	186.52	BTU/lb

Fuel:

Mass Flow Rate	=	1059.50	lb/hr
High-Heat Value	=	127885.00	BTU/gal
High-Heat Value	=	19336.59	BTU/lb
Flow Rate	=	2.67	gpm
Total Flow	=	160.00	gal
Pressure At Nozzle	=	63.96	psi
Pump Discharge Pressure	=	100.40	psi
Temperature	=	104.30	F
Atom. Fluid Pressure	=	65.30	psi

Air:

Dry Bulb Temp.	=	119.30	F
Wet Bulb Temp.	=	79.40	F
Humidity Ratio	=	.0124	lb H2O/lb dry air
Relative Humidity	=	15.70	%

Blow Down:

Flow Rate	=	.00	gal
Enthalpy	=	.00	BTU/lb

Stack:

Opacity	=	.0000	%
Economizer Inlet Temp.	=	430.3000	F
Economizer Outlet Temp.	=	293.0000	F
O2	=	2.8000	%
CO	=	1.1300	ppm
NO2	=	101.2000	ppm
CO2 (calculated)	=	13.2991	%

APPENDIX K

FULL-SCALE TEST
INORGANIC EMISSIONS SAMPLING, ANALYSIS, AND RESULTS (17)

During the period of 5-6 June, 1991, BTC Environmental performed source emissions tests for particulate matter, oxides of nitrogen, carbon monoxide and sulfur dioxide on Boiler #22 located at McClellan AFB, CA. Testing was conducted while the boiler was fired on Diesel (DF-2) at baseline conditions, JP-8 at baseline and JP-8 at performance conditions. Sampling was done in triplicate for all conditions for one (1) hour each. The boiler operated at a single load of 100 percent.

A. SAMPLING AND ANALYTICAL PROCEDURES

1. Stack Gas Analysis

Continuous sampling was done through a refrigerated water drop-out on the stack and transported through a teflon line to the analyzers. The samples were taken and analyzed according to CARB Method 100. Samples of the stack gas were taken from the exhaust stack and analyzed for oxygen, carbon dioxide, sulfur dioxide, oxides of nitrogen and carbon monoxide. The oxygen was determined with a Teledyne electrochemical cell oxygen analyzer. The carbon dioxide was checked using an ACS (Fuji) non-dispersive infrared analyzer. The sulfur dioxide was analyzed with a Western Research model 721AT SO2 UV analyzer. The NO_x was monitored with a TECO model 10 chemilumenescent NO_x analyzer. The carbon monoxide was analyzed with a TECO Model 48H gas filter correlation non-dispersive infrared analyzer. Readings were obtained continuously on a strip chart recorder for 60 minutes during each run and then averaged together to obtain the stack gas composition. A system check was performed on the sampling train to assure a leak free sample.

2. Stack Gas Velocity

The stack gas velocity was determined using an "S" type pitot tube connected to an inclined draft gauge or a magnehelic gauge. The stack temperature was determined using a thermocouple and an indicating pyrometer. The proportion of water was determined gravimetrically and the dry molecular weight of the stack gas determined by E.P.A. Method 3, equation 3-2*. Stack velocities were calculated using E.P.A. Method 2, equation 2-9 ; gas volumetric flow rate was determined by equation 2-10.

* Refer to page K-6 for a description of these E.P.A. equations, as provided by the emissions contractor, BTC Environmental.

3. Particulate Emissions

Particulate was collected using a Lace Model 31 stack sampler system that conforms to E.P.A. requirements for particulate sampling. The system consists of a heated probe, heated filter, and cooled impingers (see E.P.A. Method 5). E.P.A. Method 5 requires the weight obtained from filtering the probe rinse in addition to the weight of the material collected on the filter. Results were reported according to the E.P.A. weights recovered. California Air Resources Board (CARB) requires that the total dissolved solids in the impingers be added to the front half particulate weight. Results were reported according to the total weight obtained with the impingers. Residue blanks for the dionized water and acetone were analyzed and subtracted from the total particulate.

4. Leak Checks

Leak rates were conducted on the sampling train and the pitot tubes before and after each test. The leak check for the sampling train was done at the nozzle. Any leak rate greater than 0.02 cfm was corrected for in the volume calculations. All calculations for lb/hr were done by using the flow rate of the stack gas. All values were calculated by using E.P.A. and CARB standard conditions (68°F and 29.92 in Hg).

5. Comments

During run #1 of the JP-8 optimum test the glass u-bend connecting the probe with the filter broke. The results obtained from this run are reported in the field data summary, but are not used in the summary of results.

B. RESULTS

A summary of the collected field data for each of the runs is summarized in Tables K-1 through K-3.

TABLE K-1. FIELD DATA SUMMARY: DIESEL BASELINE

PARAMETER	RUN #1	RUN #2	RUN #3
Vol of H2O coll. (ml)	73.4	66.9	62.5
Gas vol, meter cond. (dcf)	29.200	31.130	28.025
Meter calibr. factor	0.973	0.973	0.973
Barometric P (in Hg)	30.05	30.05	30.05
Stack static P (in H2O)	-0.15	-0.14	-0.14
Avg meter P diff. (in H2O)	0.843	0.904	0.759
Absolute meter Temp (°R)	558.7	564.2	568.0
Standard sample gas vol (dscf)	27.0243	28.5339	25.4612
H2O vapor part in gas stream	11.4	10.0	10.4
CO2, dry conc. vol%	12.3	12.3	12.5
O2, dry conc. vol%	4.3	4.4	4.3
Mol wt. stack gas, dry g/gmole	30.147	30.146	30.175
Mol wt. stack gas, wet g/gmole	28.767	28.937	28.912
Pitot tube coef. (dimensionless)	0.858	0.871	0.846
Avg. of sq roots of delta P	0.442	0.450	0.423
Absol. stack T (°R)	774.9	777.7	775.0
Area of stack, SF	5.59	5.59	5.59
Vol flow rate (dscfm)	6244	6518	5928
Area of nozzle, SF	0.0004246	0.0004246	0.0004246
Sampling time, min	60	60	60
Isokinetic variation, %	97.2	98.4	96.5

TABLE K-2. FIELD DATA SUMMARY: JP-8 BASELINE

PARAMETER	RUN #1	RUN #2	RUN #3
Vol of H2O coll. (ml)	78.6	44.4	77.6
Gas vol, meter cond. (dcf)	29.998	30.162	27.985
Meter calibr. factor	0.973	0.973	0.973
Barometric P (in Hg)	30.01	30.05	30.10
Stack static P (in H2O)	-0.23	-0.21	-0.21
Avg meter P diff. (in H2O)	0.899	0.922	0.753
Absolute meter Temp (°R)	536.5	547.2	552.3
Standard sample gas vol (dscf)	28.8733	28.5046	26.2365
H2O vapor part in gas stream	11.4	6.8	12.2
CO2, dry conc. vol%	12.3	12.0	12.1
O2, dry conc. vol%	4.5	4.6	4.6
Mol wt. stack gas, dry g/gmole	30.192	30.095	30.120
Mol wt. stack gas, wet g/gmole	28.805	29.267	28.636
Pitot tube coef. (dimensionless)	0.858	0.871	0.846
Avg. of sq roots of delta P	0.467	0.461	0.426
Absol. stack T (°R)	780.8	775.7	770.3
Area of stack, SF	5.59	5.59	5.59
Vol flow rate (dscfm)	6560	6882	5910
Area of nozzle, SF	0.0004246	0.0004246	0.0004246
Sampling time, min	60	60	60
Isokinetic variation, %	98.9	93.2	99.7

TABLE K-3. FIELD DATA SUMMARY: JP-8 PERFORMANCE

PARAMETER	RUN #1	RUN #2	RUN #3
Vol of H2O coll. (ml)	7.2	74.9	77.8
Gas vol, meter cond. (dcf)	30.763	31.299	29.432
Meter calibr. factor	0.973	0.973	0.973
Barometric P (in Hg)	29.91	29.91	29.00
Stack static P (in H2O)	-0.08	-0.07	-0.07
Avg meter P diff. (in H2O)	0.906	0.970	0.799
Absolute meter Temp (°R)	564.3	573.4	573.3
Standard sample gas vol (dscf)	28.0593	28.1003	25.6166
H2O vapor part in gas stream	1.2	11.2	12.5
CO2, dry conc. vol%	13.0	12.8	13.0
O2, dry conc. vol%	3.5	3.6	3.4
Mol wt. stack gas, dry g/gmole	30.227	30.195	30.209
Mol wt. stack gas, wet g/gmole	30.080	28.833	28.679
Pitot tube coef. (dimensionless)	0.845	0.858	0.846
Avg. of sq roots of delta P	0.432	0.441	0.403
Absol. stack T (°R)	775.3	773.4	775.3
Area of stack, SF	5.59	5.59	5.59
Vol flow rate (dscfm)	6524	6218	5444
Area of nozzle, SF	0.0004246	0.0004246	0.0004246
Sampling time, min	60	60	60
Isokinetic variation, %	95.5	101.5	105.7

The results of emission summaries for each of the one hour runs are provided in Tables K-4 through K-6.

TABLE K-4. EMISSIONS SUMMARY: DIESEL BASELINE

CONSTITUENT	RUN #1	RUN #2	RUN #3	AVERAGE
Total Particulate (EPA)				
gr/DSCF	0.0058	0.0033	0.0142	0.0078
gr/DSCF @12% CO2	0.0056	0.0032	0.0135	0.0074
lb/hr	0.31	0.18	0.18	0.40
Total Particulate (CARB)				
gr/DSCF	0.0130	0.0151	0.0230	0.0173
gr/DSCF @12% CO2	0.0126	0.0148	0.0220	0.0165
lb/hr	0.69	0.85	1.17	0.90
Oxide of Nitrogen				
ppmv	65	64	65	65
ppmv @ 3% O2	70	69	70	70
lb/hr	2.91	2.99	2.76	2.89
Sulfur Dioxide				
ppmv	80	88	107	92
ppmv @ 3% O2	86	95	115	99
lb/hr	4.98	5.72	6.32	5.67
Carbon Monoxide				
ppmv	1	<1	<1	<1
ppmv @ 3% O2	1	<1	<1	<1
lb/hr	0.03	<0.03	<0.03	<0.03

TABLE K-5. EMISSIONS SUMMARY: JP-8 BASELINE

CONSTITUENT	RUN #1	RUN #2	RUN #3	AVERAGE
Total Particulate (EPA)				
gr/DSCF	0.0033	0.0005	0.0072	0.0036
gr/DSCF @12% CO2	0.0290	0.0005	0.0071	0.0122
lb/hr	0.17	0.03	0.36	0.19
Total Particulate (CARB)				
gr/DSCF	0.0055	0.0055	0.0123	0.0078
gr/DSCF @12% CO2	0.0053	0.0055	0.0122	0.0077
lb/hr	0.31	0.32	0.62	0.42
Oxide of Nitrogen				
ppmv	51	52	52	52
ppmv @ 3% O2	56	57	57	57
lb/hr	2.40	2.56	2.20	2.39

Sulfur Dioxide				
ppmv	1	<1	<1	<1
ppmv @ 3% O2	1	<1	<1	<1
lb/hr	0.07	0.07	<0.06	<0.07
Carbon Monoxide				
ppmv	<1	1	<1	<1
ppmv @ 3% O2	<1	1	<1	<1
lb/hr	<0.03	0.03	<0.03	<0.03

TABLE K-6. EMISSIONS SUMMARY: JP-8 PERFORMANCE

CONSTITUENT	RUN #1	RUN #2	RUN #3	AVERAGE
Total Particulate (EPA)				
gr/DSCF	-	0.0049	0.0090	0.0070
gr/DSCF @12% CO2	-	0.0046	0.0084	0.0065
lb/hr	-	0.26	0.42	0.34
Total Particulate (CARB)				
gr/DSCF	-	0.0072	0.0186	0.0129
gr/DSCF @12% CO2	-	0.0068	0.0172	0.0120
lb/hr	-	0.39	0.87	0.63
Oxide of Nitrogen				
ppmv	60	61	61	61
ppmv @ 3% O2	62	63	62	62
lb/hr	2.80	2.72	2.38	2.63
Sulfur Dioxide				
ppmv	3	2	2	2
ppmv @ 3% O2	3	2	2	2
lb/hr	0.20	0.12	0.11	0.14
Carbon Monoxide				
ppmv	3	1	9	4
ppmv @ 3% O2	3	1	9	4
lb/hr	0.09	0.03	0.21	0.11

C. CONCLUSIONS

Baseline JP-8 conditions resulted in significantly lower particulate, NO_x, and SO_x emissions than the measured diesel emissions. Carbon monoxide emission readings were approximately the same. JP-8 performance conditions resulted in comparable SO_x emissions to the baseline JP-8 conditions, but particulate and NO_x emission were closer to the baseline diesel emissions. Both of the JP-8 conditions resulted in much lower SO_x emissions than the diesel runs.

BTC ENVIRONMENTAL
EPA methods 2, 3, 4, 5, 6, 8

CONSTANTS & CONVERSIONS

Tstd = 60, 68, or 70 °F	1 in. Hg = 13.6 in. H2O
Pstd = 29.92 in. Hg	1 lb = 453.6 g
R = 21.85(in. Hg-cu ft/lb mole-°R)	1 lb = 7000 grain
Dw = 0.9982(g/ml)	1 g = 15.432 grain
MW(H2O) = 18.0 lb/lb mole	1 mg = 0.001 g
MW(Sulfur) = 32.03 lb/lb mole	1 hr = 60 min.
M(H2SO4) = 98.08 lb/lb mole	1 part/vol X = 1*10^6 ppmv X
MW(SO2) = 64.06 lb/lb mole	1 bbl = 42 gal
K(H2SO4) = 0.5 mg-g mole/g-meq	M = 1000
K(SO2) = 0.5 mg-g mole/g-meq	La = 0.02 cfm

Kp = 85.49(ft/sec(sqrt(lb/lb mole-in.Hg/°R-in. H2O))
Kw,[cu ft/g-°R] = R / (453.6*MW(H2O)*Pstd)
Kf,[scf-ppm/lb mole] = R * (Tstd+460) * (1*10^6) / Pstd

INTERMEDIATE CALCULATIONS

F,[scf/MMBtu] = F Factor * (Tstd + 460) / 528
Ph,[in. Hg] = Pbar + (ΔH / 13.6)
N2,[%] = 100 - (O2% + CO2%)
Vlc,[ml] = Ww / Dw
Qa,[cfm] = 60 * Vs * As
Qad,[dcfm] = Qa * (1 - Bws)

CFR 40 - EPA EQUATIONS

eq. 2-8	T[°R] = T[°F]+460
eq. 2-6	Ps, [in. Hg] = Pbar+(Pg/13.6)
eq. 5-3	Bws, [%] = Vw(std) / { Vw(std) + Vm(std) }
eq. 3-2	Md, [lb/lb-mole] = 0.44*CO2%+0.32*O2%+0.28*(N2%+CO%)
eq. 2-5	Ms, [lb/lb mol] = Md*(1-Bws)+(MW(H2O)*Bws)
eq. 5-2	Vw(std), [scf] = Ww * Kw * (Tstd+460)
eq. 5-1	Vn, [cf] = Vm - ((Lp-La) * Theta)
eq. 5-1	Vm(std), [sdcf] = Vm * Y * ((Tstd+460) / (Tm+460)) * Ph / Pstd
eq. 2-9	Vs, [ft./sec.] = Kp*Cp*(ΔP*(Ts+460)/(Ps*Ms))^0.5
eq. 2-10	Qstd, [dscfm] =Qad*(Tstd+460)*Ps/((Ts+460)*Pstd)
eq. 5-8	I,[%] =100*(Ts+460)*Vm(std)*Pstd/(60*Vs*Theta*An*Ps*(1-Bws)*(Tstd+460))
eq. 5-6	Cx, [grain/dscf] = Wx,g*15.432/Vm(std)
eq. 8-2,3	Wx, [mg] = (Vt-Vtb)*N(std)*(Vsoln/Valq)*MWx*Kx
	Cx, [grain/dscf] = Wx,mg*0.001*15.432/Vm(std)
	CWx, [grain/scf] = Cx*(1-Bws)
	CCx, [grain/dscf @ 12% CO2] = Cx*12.0/CO2%
	CWCx, [grain/scf @ 12% CO2%] = CCx
	CPx, [ppmv dry] = Cx*Kf/(MWx*7000)
	CPCx, [ppmv @ N% O2] = CPX* ((20.9-N%)/(20.9-O2%))
	CFx, [lb/hr] = Cx*Q(std)*60/7000
	CEx, [lb/MMBtu] = F*(Cx/7000)*(20.9/(20.9-O2%))
	CBx, [lb/bbl] = CEx*(Fuel Btu/MM)*(Fuel lb/gal)*42
	CEsx, [lb S/MMBtu] = CEx*(MW(S) / MWx)

Where x represents, Particulate, Sulfuric Acid, Sulfate, or Sulfur Dioxide respectively.

APPENDIX L

FULL-SCALE TEST ORGANIC EMISSIONS SAMPLING, ANALYSIS AND RESULTS

A. SAMPLE COLLECTION

Stack gases from the boiler were sampled through a stainless steel probe which had been inserted into a small hole drilled in the stack. The probe was connected to a tandem set of charcoal traps. Each trap consisted of a 5 mg pellet of charcoal secured in a piece of glass chromatography tubing, 58.5 mm long, with an outer diameter of 6 mm, and an inner diameter of 2.0 mm. These traps were commercially available as accessories for closed-loop stripping apparatus (Tekmar, Inc.). Gasses were drawn through the traps with a diaphragm-type pump, and the volume of the sample was measured with a wet gas meter. The sampling system is illustrated in Figure M-1. The internal pressure and temperature of the gas meter were indicated by a high precision absolute pressure gauge (Pennwalt Corp., Wallace & Tiernan Division) attached to the meter gauge fitting, and a type-K thermocouple which was inserted into the meter case.

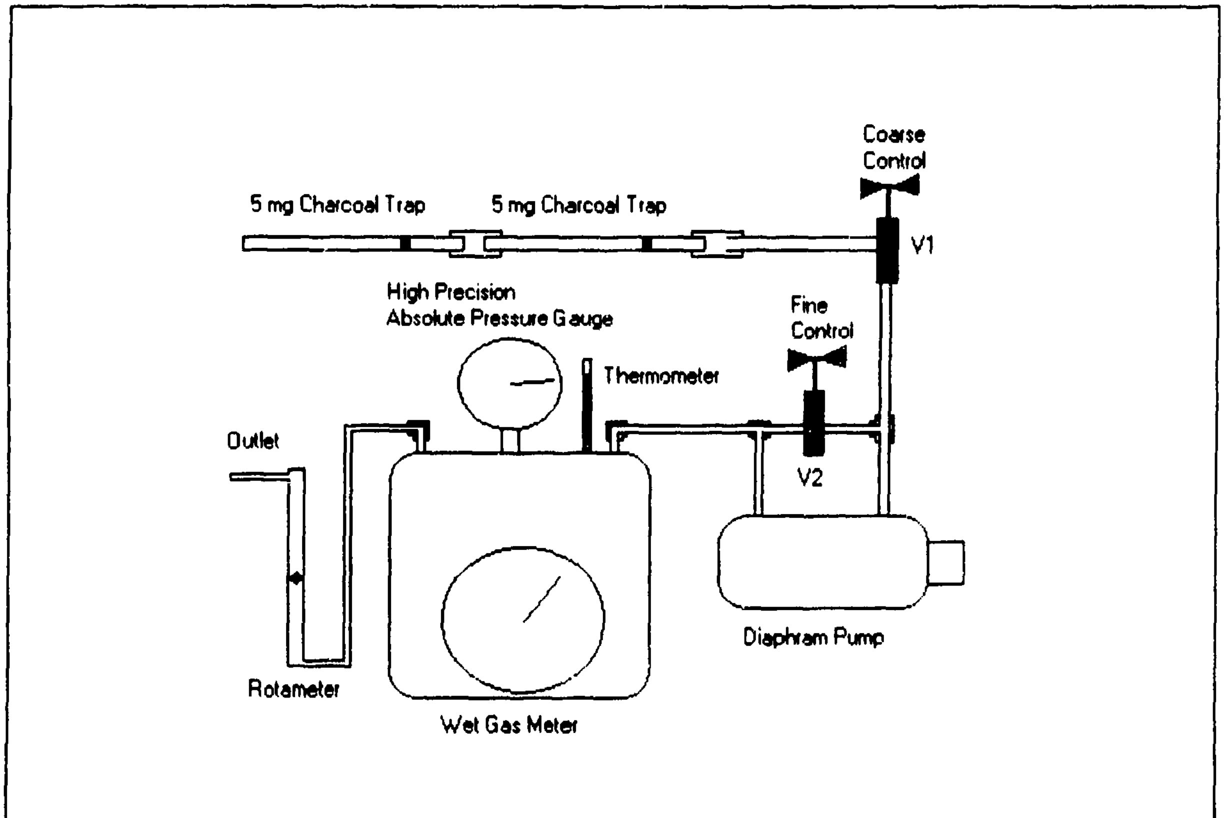

Figure L-1. Sampling System Diagram

The charcoal traps were permitted to remain at ambient temperature, and the sampled gases were permitted to cool during the transit of the probe, from the stack temperature to near ambient temperature. This was done in order to permit the organic materials to sorb onto the charcoal. Before starting the sampling pump, the volume reading of the gas meter, the meter's internal temperature, and internal pressure were recorded. The time at which the pumping started and the initial air temperature were also recorded. At intervals during the sample collection, the volume reading, rotameter readings, time, internal meter pressure and temperature, and the air temperature were recorded. When a sample was complete, the final meter and air temperatures, internal meter pressure, and the time at which the pump stopped were recorded. The meter temperatures and pressures were averaged, using a weighted average calculation with the intervals between readings serving as weight factors. Using the average temperature and pressure, the indicated sample volume could be converted to standard conditions using ideal gas law equations.

After sampling, the traps were removed from the sample train and were placed in a closed vial until the sorbed organics could be recovered. For recovery, each trap was attached to a glass collection vessel which was constructed of glass tubing of a diameter which matched that of the trap tube, sealed at one end, and tapering inside. Traps and collection vessels were attached with a short piece of Teflon® tubing which had been heat-shrunk to match the diameter of the traps and collection vessels. In order to recover the trapped organic compounds, 50 microliters of dichloromethane were placed in the trap tube, just above the charcoal pellet, and the solvent was then drawn through the charcoal by chilling the trap-collector assembly in an ice bath. The solvent could also be passed back through the charcoal by gently warming the trap-collector assembly by hand. By alternately chilling and warming the trap-collector assembly, the solvent slug was passed five times back-and-forth through the charcoal to extract the organics. Following the last extraction, the trap-collector assembly was chilled to move as much of the solvent as possible into the collector vessel. The solvent was then shaken into the bottom of the collector vessel. Finally, the extract was transferred from the collector assembly to a 100 microliter autosampler vial with a screw-cap closure and a teflon-faced rubber septum. The vials containing the extracts were labelled and stored in an ice chest or freezer.

After the samples were received at the laboratory, aliquots of each extract were analyzed by gas chromatography with flame-ionization detection. The gas chromatograph was a Hewlett-Packard 5890 equipped with a flame-ionization detector and a split/splitless injector. One-microliter samples were injected using the splitless injection technique. The column was a high-efficiency fused-silica capillary column, 10 meters long with a diameter of 0.1mm, and coated with a 0.34-micrometer film of crosslinked 5 percent phenyl-substituted polymethylsiloxane (HP-5, Hewlett-Packard Company). The analytical conditions are listed in Table L-1. The flame-ionization signal was monitored and stored by a mini-computer based laboratory data system (HP-3357, Hewlett-Packard Company), which was also used to display the chromatograms and integrate peaks.

TABLE L-1. GAS CHROMATOGRAPHIC CONDITIONS

COLUMN TYPE:	FUSED SILICA CAPILLARY
COLUMN STATIONARY PHASE:	HP-5
COLUMN STATIONARY PHASE THICKNESS:	0.34 µm
COLUMN LENGTH:	10 M
COLUMN INNER DIAMETER:	0.10 MM
DETECTOR TYPE:	FLAME IONIZATION DETECTOR
INITIAL TEMP:	40 °C
INITIAL ISOTHERMAL HOLD TIME:	2 MIN
TEMP PROGRAMMING RATE:	12 °C/MIN
FINAL TEMP:	250 °C
FINAL ISOTHERMAL HOLD TIME:	10 MIN
INJECTOR TEMP:	250 °C
DETECTOR TEMP:	270 °C
INJECTION PORT PURGE START TIME:	0.34 MIN
INJECTION PORT PURGE STOP TIME:	29 MIN

An internal standard procedure was used to estimate the total organic compound mass in each extract, which in turn yielded the total organic compound mass in each sample and the total organic concentration in the stack gases. The organic compound concentration obtained from the traps were never high enough to permit the organic species in the stack gas to be identified. Thus, it was not possible to prepare a specific, representative standard to calibrate the gas chromatographic analysis. Instead, the procedure was calibrated using a series of n-alkanes. The standard solutions were prepared in dichloromethane from the same supply which had been used to extract organics collected from the stack. This dichloromethane supply contained cyclohexane at a concentration of 160 ppm as a preservative, and the cyclohexane peak in the chromatograms was used as an internal standard. The most concentrated calibration standard was designated Solution A, and was prepared with the analytes and concentrations listed in Table L-2. Four dilutions of the primary standard were made in order to provide a five-point standard curve. These dilutions are listed in Table L-3.

TABLE L-2. STANDARD SOLUTION A COMPOSITION

Component	Concentration (mg/l)
n-decane	292.0
n-undecane	370.1
n-dodecane	449.2
n-tridecane	378.2
n-tetradecane	305.1
n-pentadecane	384.2
n-hexadecane	464.0
n-heptadecane	389.0

TABLE L-3. PREPARATION OF STANDARD DILUTIONS

Solution	Volume of Standard Solution A (µL)	Volume of Dichloromethane (mL)
Sol. B	0.5	50
Sol. E	1.0	50
Sol. F	1.5	50
Sol. G	2.0	50

Each of the standard solutions was injected into the gas chromatograph and analyzed using conditions identical to those used to analyze stack sample extracts. The low signal levels exhibited by many of the stack sample extracts made the detection and integration of peaks difficult for the normal HP-3357 software. More accurate and consistent peak integrations were achieved by importing the portions of the chromatograms following the dichloromethane peak into the data analysis system of a Hewlett-Packard RTE-6/VM GC/MS Data System, which was co-resident on the same HP-1000 minicomputer as the HP-3357 laboratory automation system. The area of the cyclohexane peak in each chromatogram was separated from the remaining peaks and utilized as an internal standard value.

For each chromatogram, a total hydrocarbon response figure was obtained by dividing the total area of all hydrocarbon analyte peaks by the area of the cyclohexane internal standard. Thus, from a chromatogram with analyte peak areas A_1 through A_n, and cyclohexane peak area A_s the total hydrocarbon response R_h is given by Equation L-1.

$$R_h = \frac{\Sigma A_h}{A_s} \qquad \text{(L-1)}$$

The chromatograms of the standard solutions were used to obtain the best fit of the Response versus the concentration of total hydrocarbons in the sample. This could then be used to calculate the concentration of the total hydrocarbons in the boiler standards.

Each sampling produced extracts from a pre-trap and a post trap. The total analyte peak area and cyclohexane internal standard peak area from each extract chromatogram were used to provide a hydrocarbon response figure for that extract. The total hydrocarbon response figure could be used with the standard curve to give a total hydrocarbon content estimate for each extract. The total hydrocarbon concentration in the stack gas during each sampling run can then be found using Equation L-2, where C is the concentration of hydrocarbons in the stack gas, M_1 is the mass of hydrocarbons in the pre-trap sample, M_2 is the mass of hydrocarbons in the post-trap sample, and V_{std} is the volume of stack gas sampled corrected to standard conditions. Standard conditions are taken to be 25 °C and 760 torr.

$$C = \frac{M_1 + M_2}{V_{std}} \qquad \text{(L-2)}$$

B. RESULTS

Analyses of the primary standard solution, Solution A, and the four dilutions thereof yielded a standard curve shown in Figure L-2. These standard response data are tabulated in Table L-4. Since all of the stack gas extracts were found to be extremely dilute, only the four dilute standards, B, and E-G were used to obtain a best-fit line to describe the standard curve for quantitating the unknown extracts. A line was found which fit the dilute standard chromatogram data satisfactorily, giving a regression coefficient R^2 of 0.956. This best-fit standard curve was used with the total hydrocarbon responses from the boiler sample extracts to estimate the amount of total hydrocarbons in each extract. The slope m and y-intercept b of the standard line were solved to obtain the concentration of hydrocarbons in each extract, E, as shown in Equation L-3. The mass M of hydrocarbons in each extract is then given in Equation L-4, where V_e is the volume of extracting solvent used to obtain the extract. The total hydrocarbon mass from the pre-trap and post-trap samples of each collection run, and V_{std} were used with Equation L-2 to give the total hydrocarbon concentration from that sampling period.

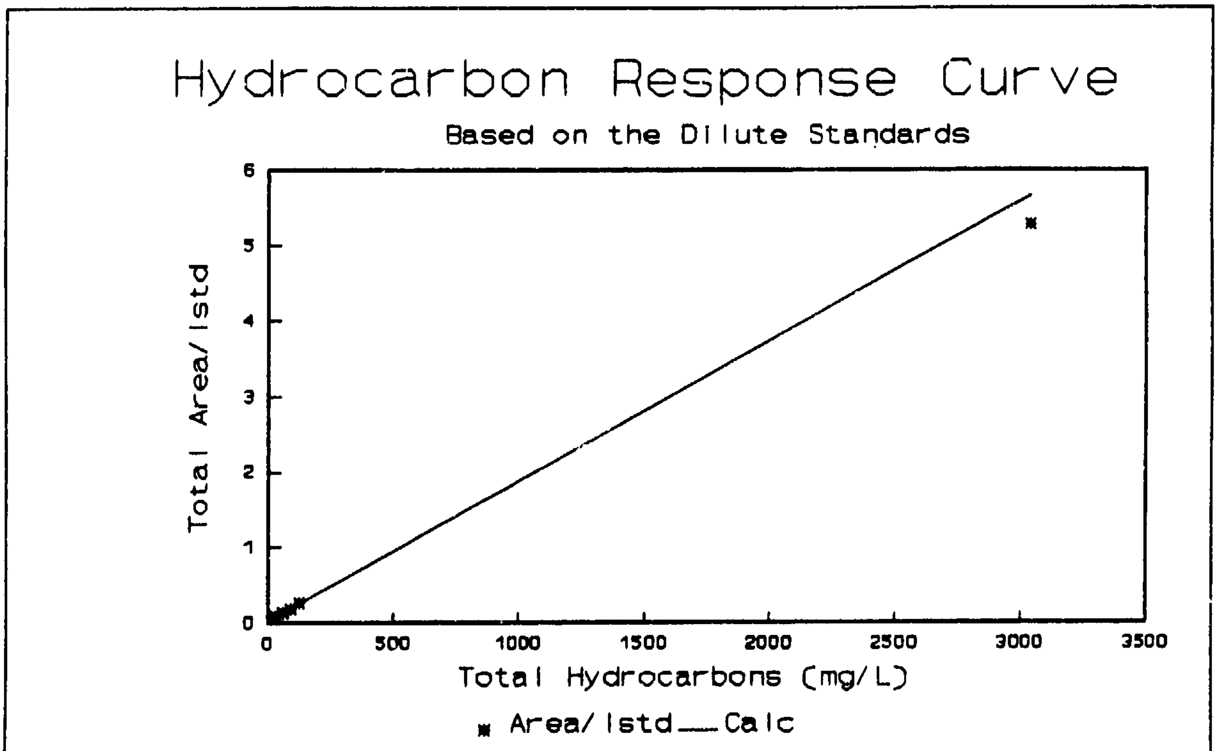

Figure L-2. Total hydrocarbon response standard curve.

$$E = \frac{R_h - b}{m} \tag{L-3}$$

$$M = EV_s \tag{L-4}$$

The results from the stack samplings, including pre- and posttrap hydrocarbon masses, V_{std}, and stack gas concentrations are listed in Table L-5.

The highest concentration measurement of hydrocarbons in the stack gas was obtained while the boiler was operating in a normal manner, with the boiler power setting being continually adjusted to follow the load requirement, except that the boiler was operating with JP-8 fuel instead of with its normal fuel. The pre-trap chromatogram from that observation is shown in Figure L-3, and the profile very closely resembles that of JP-8 fuel. The post-trap chromatogram from that observation is shown in Figure L-4, and indicates that a small amount of material did break through the pre-trap. An examination of the boiler operating records showed that during this observation, the boiler was shut down prior to the end of sample collection. During tests with the small-scale boiler at Tyndall AFB, it was noted that when the boiler flame shut off unexpectedly during sampling, the sample always showed a relatively high concentration profile which matched that of the operating fuel. The large scale boiler also appears to have exhibited this phenomenon. No other unexpected shut-downs occurred, and the remaining samples were taken while the boiler was operated at full power, with excess steam being vented.

TABLE L-4. TOTAL HYDROCARBON RESPONSE FROM STANDARD SOLUTIONS

Solution	Conc, Total HC (mg/L) (X)	Experimental Response (Y)
Soln A	3032	5.659
Soln G	121.3	0.243
Soln F	90.96	0.187
Soln E	60.64	0.130
Soln B	30.32	0.074
Slope:	1.861×10^{-3}	
Y-Intercept:	1.756×10^{-2}	
R^2:	0.956	

TABLE L-5. TOTAL HYDROCARBON CONCENTRATION IN STACK GAS SAMPLES

Sample	Pre-trap Hydrocarbon Mass (μg)	Post-trap Hydrocarbon Mass (μg)	Vol.@ Stand. Cond. (cuft)	Conc. (μg/L)
JP-8 Normal Boiler	88.4	8.81	0.6906	4.97
Performance JP-8, No. 1	0.357	0.474	0.715	0.0411
Performance JP-8, No. 2	3.86	2.01	0.564	0.367
Performance JP-8, No. 3	0.411	0.294	0.969	0.0257
Baseline JP-8, No. 1	0.465	0.0715	0.759	0.0249
Baseline JP-8, No. 2	0.573	0.709	0.821	0.0551
Baseline JP-8, No. 3	0.2276	0.318	0.741	0.0259
Baseline DF-2, No. 1	0.717	0.199	0.835	0.0388
Baseline DF-2, No. 2	0.147	0.156	0.530	0.0202
Baseline DF-2, No. 3	1.81	2.45	0.830	0.181

The extracts from the nine full-power test runs showed much lower amounts of organic substances. Most of the extracts showed only a few small peaks which were near the limits of detectability for the methods used. A typical chromatogram from the full-power runs is shown in Figure L-5. The peaks shown are too small to quantitate reliably. Clearly, the sampling method did not obtain large enough samples. Re-collection of the samples using modified conditions would normally be indicated, but this was not practical.

A number of quality control extracts were also made, and they indicated that trap tubes being placed in-service for the first time needed more than the five aliquots of extraction solution which were used to clean them out. Most of the actual sample extracts were found to be cleaner than the initial quality

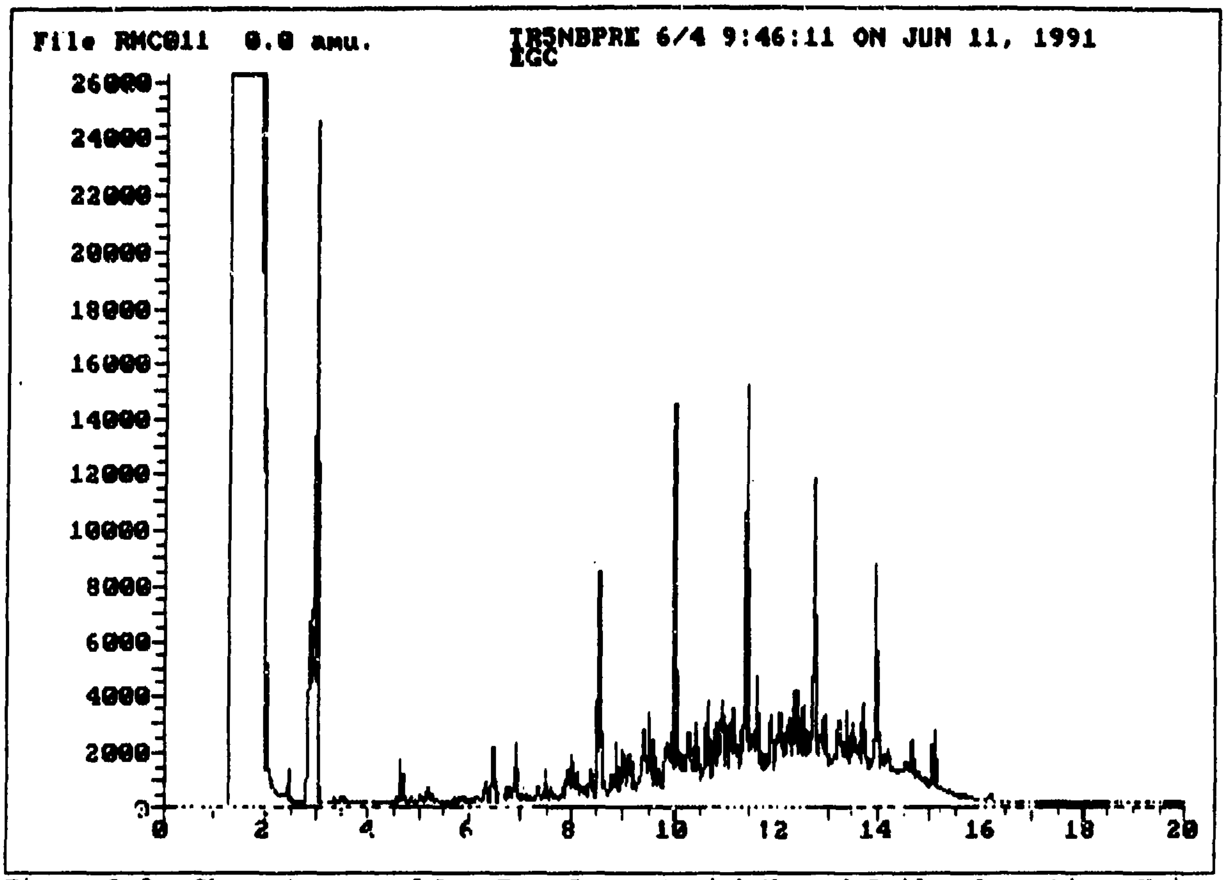

Figure L-3. Chromatogram of Pre-Trap Extract with Normal Boiler Operations Using JP-8.

control extract, but they exhibited different peaks. Thus, the peaks in the typical stack sample extracts were considered to be genuine peaks. A few sample extracts were found with chromatograms which showed profiles similar to the contaminated quality control extracts. Such extracts were encountered when a trap tube was in use for the first time, despite extensive measures to clean the tubes out prior to use. The Performance JP-8 Sample 1, and the Baseline Diesel Sample 3 showed this type of profile. A chromatogram of one of the contaminated quality control extracts is shown in Figure L-6. The high hydrocarbon concentration values from these samples probably results from material which was not removed from the trap by cleaning until after the first use sample had been collected. The trap tubes appear to have become cleaner after being used for an actual sampling than they were after their initial cleaning.

C. CONCLUSIONS

Under all three sets of test conditions, the full-scale boiler produced very little organic emission. The only significant

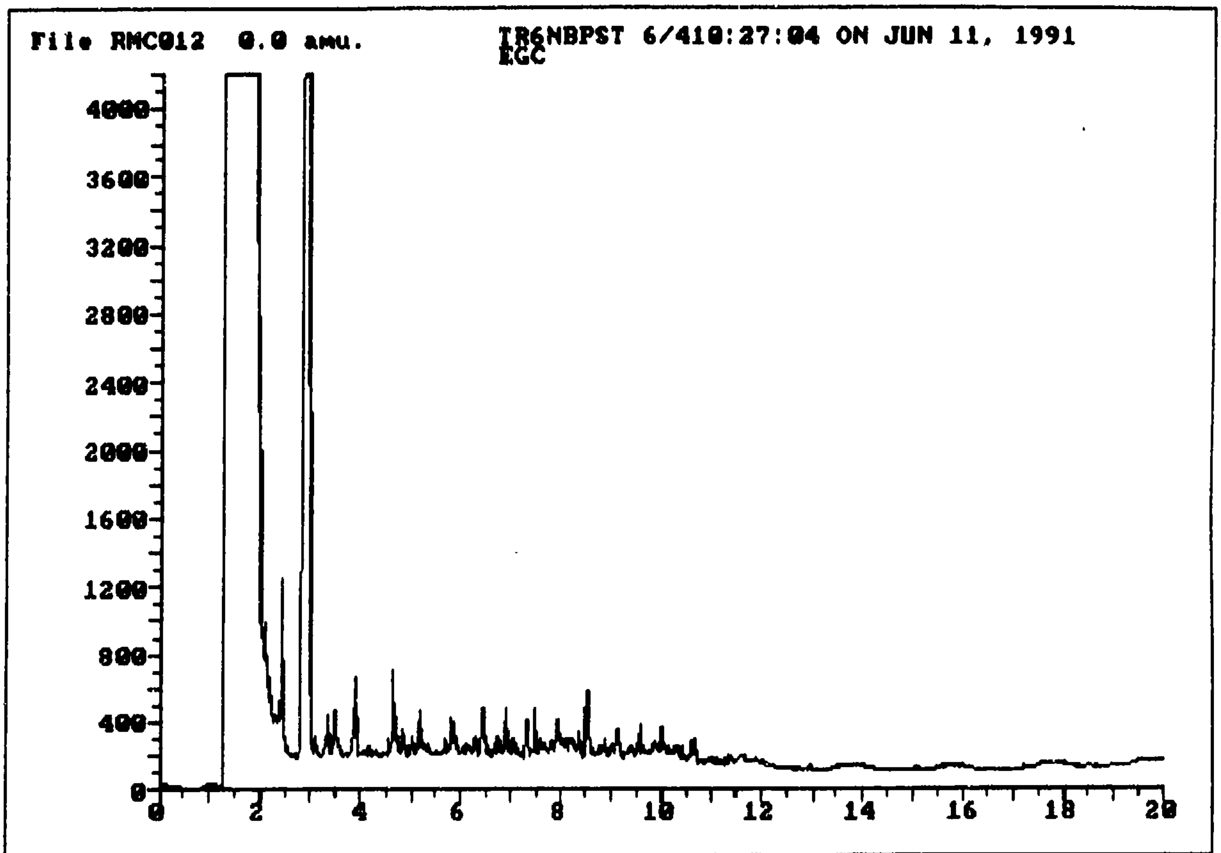

Figure L-4. Chromatogram of Post Trap Extract with Normal Boiler Operations with JP-8.

organic emission noted occurred during a period when the boiler was operating to follow the base steam demand and the boiler fire was extinguished prior to the ending of the sample period. This is in agreement with the results from the small-scale test boiler, where significant organic emissions closely resembling the original fuel were seen whenever the boiler was shut-down during a sampling period. No observations were made of the boiler following the base demand but with continuous firing, so the full-scale high organic artifact cannot conclusively be blamed on the loss of firing, but such a cause is suggested by the combined small-scale and full-scale results. This, in turn, may indicate that the frequency of firing loss and restarting may be a more important factor in the organic emissions than the fuel type.

The sample collection rates and periods largely determined the volume of stack gases sampled with each collection. The sampling periods and rates were based on experience with the small-scale test boiler, which experienced frequent loss of fire and exhibited corresponding high organic emission values. The organic emissions collected during the full-power emission test runs were much smaller than those obtained from the small-scale emission tests,

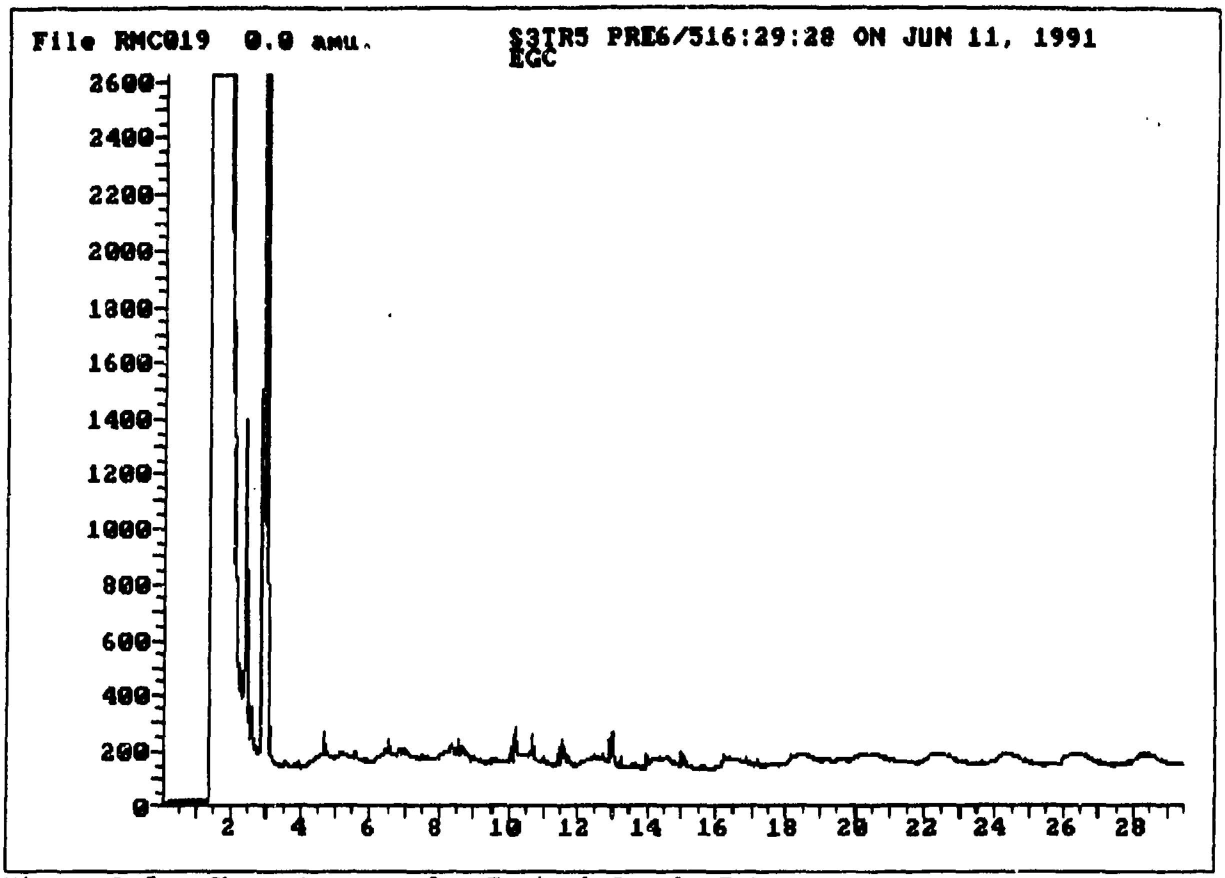

Figure L-5. Chromatogram of a Typical Sample Extract.

such that the sample collection conditions used for the full-scale tests were not fully appropriate. Any future organic emission samplings to be conducted from a full-scale boiler operating continuously at full-power should be designed to collect sample volumes between 100 and 1000 times larger than were used for these collections.

Disregarding the results from Performance JP-8 Sample 1 and Baseline Diesel Sample 3, due to the chromatograms resembling the high quality control profiles, the stack gases from the performance JP-8 runs were found to contain an average of 0.033 µg/L of hydrocarbons. The stack gases from the baseline JP-8 runs were estimated to contain an average of 0.035 µg/L hydrocarbons and the stack gases from the baseline diesel fuel runs were estimated to contain 0.029 µg/L hydrocarbons. Taking the variation between runs into account indicates that these differences are not significant. Thus the fuel type used appears to have little impact on the boiler organic emissions so long as the boiler fire is not extinguished.

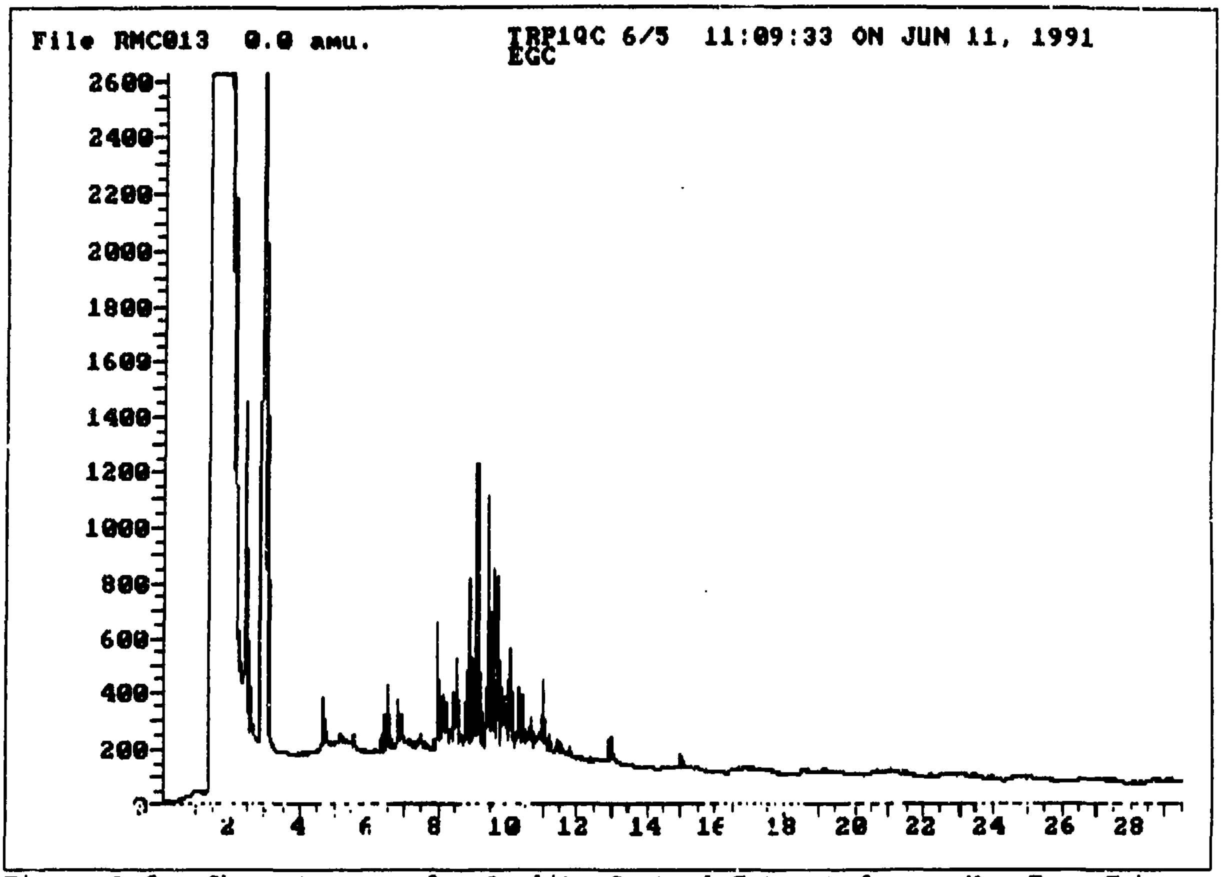

Figure L-6. Chromatogram of a Quality Control Extract from a New Trap Tube, Showing a Contamination Profile which Persisted Through the First Sample Extract.

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